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, 2017

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**
001-05152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **888-221-7070**	**93-0246090**
333-90553	**MIDAMERICAN FUNDING, LLC** **(An Iowa Limited Liability Company)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**47-0819200**
333-15387	**MIDAMERICAN ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**42-1425214**
000-52378	**NEVADA POWER COMPANY** **(A Nevada Corporation)** **6226 West Sahara Avenue** **Las Vegas, Nevada 89146** **702-402-5000**	**88-0420104**
000-00508	**SIERRA PACIFIC POWER COMPANY** **(A Nevada Corporation)** **6100 Neil Road** **Reno, Nevada 89511** **775-834-4011**	**88-0044418**

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

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Registrant	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
BERKSHIRE HATHAWAY ENERGY COMPANY			X		
PACIFICORP			X		
MIDAMERICAN FUNDING, LLC			X		
MIDAMERICAN ENERGY COMPANY			X		
NEVADA POWER COMPANY			X		
SIERRA PACIFIC POWER COMPANY			X		

If an emerging growth company, indicate by check mark if the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

All shares of outstanding common stock of Berkshire Hathaway Energy Company are privately held by a limited group of investors. As of February 16, 2018, 77,174,325 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly owned by Berkshire Hathaway Energy Company. As of February 16, 2018, 357,060,915 shares of common stock, no par value, were outstanding.

All of the member's equity of MidAmerican Funding, LLC is held by its parent company, Berkshire Hathaway Energy Company, as of February 16, 2018.

All shares of outstanding common stock of MidAmerican Energy Company are owned by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of February 16, 2018, 70,980,203 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are owned by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of February 16, 2018, 1,000 shares of common stock, $1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are owned by its parent company, NV Energy, Inc. As of February 16, 2018, 1,000 shares of common stock, $3.75 par value, were outstanding.

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

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

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Definition of Abbreviations and Industry Terms

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

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

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

Certain Industry Terms

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

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

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the relevant Registrant's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of each Registrant and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in, and compliance with, laws and regulations, including income tax reform, initiatives regarding deregulation and restructuring of the utility industry, and reliability and safety standards, affecting the respective Registrant'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 regulatory rate reviews and other proceedings conducted by regulatory agencies or other governmental and legal bodies and the respective Registrant's ability to recover costs through rates in a timely manner;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, new technologies and various conservation, energy efficiency and private generation measures and programs, that could affect customer growth and usage, electricity and natural gas supply or the respective Registrant's ability to obtain long-term contracts with customers and suppliers;
- performance, availability and ongoing operation of the respective Registrant's facilities, including facilities not operated by the Registrants, due to the impacts of market conditions, outages and repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the control of each respective Registrant or by a breakdown or failure of the Registrants' operating assets, including severe storms, floods, fires, earthquakes, explosions, landslides, an electromagnetic pulse, mining incidents, litigation, wars, terrorism, embargoes, and cyber security attacks, data security breaches, disruptions, or other malicious acts;
- a high degree of variance between actual and forecasted load or generation that could impact a Registrant'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 respective Registrant'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 interest rates;
- changes in the respective Registrant's credit ratings;
- risks relating to nuclear generation, including unique operational, closure and decommissioning risks;
- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings;
- the impact of certain contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of certain contracts;
- the impact of inflation on costs and the ability of the respective Registrants to recover such costs in regulated rates;
- fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar;
- increases in employee healthcare costs;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;

- changes in the residential real estate brokerage, mortgage and franchising industries and regulations that could affect brokerage, mortgage and franchising transactions;
- the ability to successfully integrate future acquired operations into a Registrant's business;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future facilities and infrastructure additions;
- the availability and price of natural gas in applicable geographic regions and demand for natural gas supply;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the consolidated financial results of the respective Registrants; and
- other business or investment considerations that may be disclosed from time to time in the Registrants' filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Registrants are described in the Registrants' filings with the SEC, including Item 1A and other discussions contained in this Form 10-K. Each Registrant undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Business

GENERAL

BHE is a holding company that owns a highly diversified portfolio of locally managed businesses principally engaged in the energy industry and is a consolidated subsidiary of Berkshire Hathaway. As of February 16, 2018, Berkshire Hathaway, Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with his family members and related or affiliated entities) and Mr. Gregory E. Abel, BHE's Executive Chairman, beneficially owned 90.2%, 8.8% and 1.0%, respectively, of BHE's voting common stock.

Berkshire Hathaway Energy's operations are organized as eight business segments: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), NV Energy (which primarily consists of Nevada Power and Sierra Pacific), Northern Powergrid (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which consists of Northern Natural Gas and Kern River), BHE Transmission (which consists of AltaLink and BHE U.S. Transmission), BHE Renewables and HomeServices. BHE, through these locally managed and operated 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 investing in solar, wind, geothermal and hydroelectric projects, the second largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

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

- 89% of Berkshire Hathaway Energy's consolidated operating income during 2017 was generated from rate-regulated businesses.
- The Utilities serve 4.9 million electric and natural gas customers in 11 states in the United States, Northern Powergrid serves 3.9 million end-users in northern England and ALP serves approximately 85% of Alberta, Canada's population.
- As of December 31, 2017, Berkshire Hathaway Energy owned approximately 31,800 MW of generation capacity in operation and under construction:
    - Approximately 27,500 MW of generation capacity is owned by its regulated electric utility businesses;
    - Approximately 4,300 MW of generation capacity is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts;
    - Berkshire Hathaway Energy's generation capacity in operation and under construction consists of 33% natural gas, 31% wind and solar, 29% coal, 4% hydroelectric and 3% nuclear and other; and
    - As of December 31, 2017, Berkshire Hathaway Energy has invested $21 billion in solar, wind, geothermal and biomass generation facilities.
- Berkshire Hathaway Energy owns approximately 32,900 miles of transmission lines and owns a 50% interest in ETT that has approximately 1,200 miles of transmission lines.
- The BHE Pipeline Group owns approximately 16,400 miles of pipeline with a market area design capacity of approximately 8.1 Bcf of natural gas per day and transported approximately 8% of the total natural gas consumed in the United States during 2017.
- HomeServices closed over $107.8 billion of home sales in 2017, up 24.6% from 2016, and continued to grow its brokerage, mortgage and franchise businesses. HomeServices' franchise business operates in 47 states with over 365 franchisees throughout the country.

As of December 31, 2017, Berkshire Hathaway Energy had approximately 23,000 employees, of which approximately 8,300 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 August 2024. HomeServices currently has nearly 41,000 real estate agents who are independent contractors and not employees.

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

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

PACIFICORP

General

PacifiCorp, an indirect wholly owned subsidiary of BHE, is a United States regulated electric utility company headquartered in Oregon that serves 1.9 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 141,000 square miles and includes diverse regional economies across six states. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology, recreation and government. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology, government and primary metals. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads and existing wholesale transactions. Certain PacifiCorp subsidiaries support its electric utility operations by providing coal mining services.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of the franchise agreements is approximately 25 years, although their terms range from five years to indefinite. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investments.

PacifiCorp's principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, and its telephone number is (888) 221-7070. PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

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

Regulated Electric Operations

Customers

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

	2017		2016		2015	
Utah	24,134	44%	24,020	44%	24,158	44%
Oregon	13,200	24	12,869	24	12,863	24
Wyoming	9,330	17	9,189	17	9,330	17
Washington	4,221	8	3,982	7	4,108	8
Idaho	3,603	6	3,510	7	3,443	6
California	762	1	748	1	739	1
	55,250	100%	54,318	100%	54,641	100%

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

	2017		2016		2015	
GWh sold:						
Residential	16,625	27%	16,058	26%	15,566	25%
Commercial(1)	17,726	28	16,857	28	17,262	27
Industrial, irrigation, and other(1)	20,899	33	21,403	35	21,813	34
Total retail	55,250	88	54,318	89	54,641	86
Wholesale	7,218	12	6,641	11	8,889	14
Total GWh sold	62,468	100%	60,959	100%	63,530	100%
Average number of retail customers (in thousands):						
Residential	1,622	87%	1,599	87%	1,574	87%
Commercial	208	11	205	11	202	11
Industrial, irrigation, and other	37	2	37	2	37	2
Total	1,867	100%	1,841	100%	1,813	100%

(1) In the current year, one customer was reclassified from "Industrial, irrigation and other" into "Commercial" resulting in an increase of 61 GWh to "Commercial."

Variations in weather, economic conditions and various conservation, energy efficiency and private generation measures and programs can impact customer usage. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, occurs in the summer when air conditioning and irrigation systems are heavily used. The winter also experiences a peak demand due to heating requirements. During 2017, PacifiCorp's peak demand was 10,334 MW in the summer and 9,216 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, 2017:

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	754	754
Naughton Nos. 1, 2 and 3[2]	Kemmerer, WY	Coal	1963-1971	637	637
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak No. 1	Gillette, WY	Coal	1978	332	266
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	855	165
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	441	77
				9,289	5,924
NATURAL GAS:					
Lake Side 2	Vineyard, UT	Natural gas/steam	2014	631	631
Lake Side	Vineyard, UT	Natural gas/steam	2007	546	546
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	524	524
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				2,996	2,766
HYDROELECTRIC:[3]					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	26	26
				1,135	1,135
WIND:[3]					
Foote Creek	Arlington, WY	Wind	1999	41	32
Leaning Juniper	Arlington, OR	Wind	2006	100	100
Marengo	Dayton, WA	Wind	2007-2008	210	210
Seven Mile Hill	Medicine Bow, WY	Wind	2008	119	119
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Glenrock	Glenrock, WY	Wind	2008-2009	138	138
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
McFadden Ridge	McFadden, WY	Wind	2009	28	28
Dunlap Ranch	Medicine Bow, WY	Wind	2010	111	111
				1,039	1,030
OTHER:[3]					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				14,491	10,887

(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) As required by previous state permits, PacifiCorp planned to remove Naughton Unit No. 3 (280 MW) from coal-fueled service by year-end 2017. However, a request was submitted to and was considered by the state of Wyoming that would allow the unit to operate as a coal-fueled unit until no later than January 30, 2019, and then either close or be converted to natural gas. On March 17, 2017, the state of Wyoming issued the extension to operate the unit as a coal-fueled unit through January 30, 2019. Also, the updated Wyoming regional haze state implementation plan reflecting the extension has been submitted to the EPA for review and action. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

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

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

	2017	2016	2015
Coal	56%	56%	61%
Natural gas	11	15	14
Hydroelectric[1]	7	6	4
Wind and other[1]	5	5	4
Total energy generated	79	82	83
Energy purchased - short-term contracts and other	11	10	9
Energy purchased - long-term contracts (renewable)[1]	10	8	5
Energy purchased - long-term contracts (non-renewable)	—	—	3
	100%	100%	100%

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

PacifiCorp is required to have resources available to continuously meet its customer needs and reliably operate its electric system. 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 places 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. 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, natural gas-fueled or certain types of interruptible load. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives and may include forwards, options, swaps and other agreements. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and to PacifiCorp's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Coal

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Bridger surface and Bridger underground coal mines. These mines supplied 16%, 15% and 18% of PacifiCorp's total coal requirements during the years ended December 31, 2017, 2016 and 2015, respectively. The remaining coal requirements are acquired through long and short-term third-party contracts.

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

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. PacifiCorp's recoverable coal reserves of operating mines as of December 31, 2017, based on recent engineering studies, were as follows (in millions):

Coal Mine	Location	Generating Facility Served	Mining Method	Recoverable Tons	
Bridger	Rock Springs, WY	Jim Bridger	Surface	29	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	6	(1)
Trapper	Craig, CO	Craig	Surface	4	(2)
				39	

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

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

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

Natural Gas

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

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

Hydroelectric

The amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, generating unit availability and restrictions imposed by oversight bodies due to competing water management objectives.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 99% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. The licenses for major hydroelectric generating facilities expire at various dates through May 2058. A portion of this portfolio is licensed under the Oregon Hydroelectric Act. For discussion of PacifiCorp's hydroelectric relicensing activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Wind and Other Renewable Resources

PacifiCorp has pursued renewable resources as a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Renewable resources have low to no emissions and require little or no fossil fuel. PacifiCorp's wind-powered generating facilities, including those facilities where a significant portion of the equipment is expected to be replaced, 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 began expiring in 2016, with final expiration in 2020.

Wholesale Activities

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

Transmission and Distribution

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

PacifiCorp's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. PacifiCorp's transmission and distribution systems included approximately 16,500 miles of transmission lines in nine states, 64,000 miles of distribution lines and 900 substations as of December 31, 2017.

PacifiCorp's transmission and distribution system is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

- On property owned or used through agreements by PacifiCorp;
- Under or over streets, alleys, highways and other public places, the public domain and national forests and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the title holder of record; or
- Under or over Native American reservations through agreements with the United States Secretary of Interior or Native American tribes.

It is possible that some of the easements and the property over which the easements were granted may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

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

PacifiCorp will continue to monitor regional market expansion efforts, including creation of a regional Independent System Operator ("ISO"). California Senate Bill No. 350, which was passed in October 2015, authorized the California legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO during the 2017 legislative session. The California legislature did not pass any legislation related to a regional ISO during its 2017 legislative session, which closed September 15, 2017.

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 135-mile, 345-kV Populus to Terminal transmission line between the Terminal substation near the Salt Lake City Airport and the Populus substation in Downey, Idaho placed in-service in 2010; (b) the 100-mile, 345/500-kV Mona to Oquirrh 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 170-mile, 345-kV transmission line between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah placed in-service in May 2015; and (d) other segments that are expected to be placed in-service in future years, depending on load growth, siting, permitting and construction schedules. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2017, $1.9 billion had been spent and $1.6 billion, including AFUDC, had been placed in-service.

Future Generation, Conservation and Energy Efficiency

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an IRP to develop a long-term resource plan to ensure that PacifiCorp can continue to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs, accounting for planning uncertainty, risks, reliability, state energy policies and other factors. The IRP is prepared following a public process, which provides an opportunity for stakeholders to participate in PacifiCorp's resource planning process. PacifiCorp files its IRP on a biennial basis with the state commissions in each of the six states where PacifiCorp operates. Five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states.

In April 2017, PacifiCorp filed its 2017 IRP with its state commissions. The IRP includes investments in renewable energy resources, upgrades to the existing wind fleet, and energy efficiency measures to meet future customer needs. On December 11, 2017, the OPUC acknowledged PacifiCorp's 2017 IRP.

Requests for Proposals

PacifiCorp issues individual Request for Proposals ("RFP"), each of which typically focuses on a specific category of generation resources consistent with the IRP or other customer-driven demands. The IRP and the RFPs provide for the identification and staged procurement of resources to meet load or renewable portfolio standard requirements. Depending upon the specific RFP, applicable laws and regulations may require PacifiCorp to file draft RFPs with the UPSC, the OPUC and the WUTC. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

As required by applicable laws and regulations, PacifiCorp filed its draft 2017R RFP with the UPSC in June 2017 and with the OPUC in August 2017. The UPSC and the OPUC approved PacifiCorp's 2017R RFP in September 2017. The 2017R RFP was subsequently released to the market on September 27, 2017. The 2017R RFP sought up to 1,270 MW of new wind resources that can interconnect to PacifiCorp's transmission system in Wyoming once a proposed high-voltage transmission line is constructed. The 2017R RFP sought proposals for wind resources located outside of Wyoming capable of delivering all-in economic benefits for PacifiCorp's customers. The proposed high-voltage transmission line and new wind resources must be placed in service by December 31, 2020, to maximize potential federal production tax credit benefits for PacifiCorp's customers. Bids were received in October 2017 and best-and-final pricing, reflecting changes in federal tax law, was received in December 2017. PacifiCorp finalized its bid-selection process and established a final shortlist in February 2018. PacifiCorp has identified four winning wind resource bids from this solicitation totaling 1,311 MWs, consisting of 1,111 MWs owned and 200 MW as a power-purchase agreement.

PacifiCorp released the 2017S RFP to the market on November 15, 2017. The 2017S RFP is seeking bids for new solar resources that can deliver energy and capacity to PacifiCorp's transmission system that provide net benefits for customers. The 2017S RFP is open to bidders offering power purchase agreements for new solar facilities sized between 10 and 300 MW. Bids were due in December 2017, and best-and-final pricing was received in February 2018. PacifiCorp is currently finalizing its bid-selection process and is on track to establish a final shortlist in March 2018.

Utah Subscriber Solar Program

In October 2015, the UPSC approved the Utah Subscriber Solar Program that allows Utah customers to meet a portion or all of their energy requirements from Utah-based solar photovoltaic resources. The program is an alternative for customers who are unable or do not want to install solar on their property. Residential and small commercial participants are able to subscribe in 200 kilowatt-hour blocks up to their total annual average usage. Large commercial and industrial participants are able to subscribe in 1 kilowatt blocks up to their total annual average usage. As part of the program, PacifiCorp issued a 2015 Solar RFP to seek solar photovoltaic resources up to 20 MW sited in Utah. The contract for the solar resource was executed in January 2016 and the project was operational in December 2016. During the first six months of production, the program maintained a subscription effective rate above 94%, and has been 100% sold out since August 2017. A waitlist of customers has started to build and PacifiCorp is working on a potential second RFP to expand the program offering. The program received a Green Power Leadership Award in October 2017, from the Center for Resource Solutions, which was presented at the Renewable Energy Markets conference in New York City.

Demand-side Management

PacifiCorp has provided a comprehensive set of DSM programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for energy project management, efficient building operations and efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates. During 2017, PacifiCorp spent $139 million on these DSM programs, resulting in an estimated 669,876 MWh of first-year energy savings and an estimated 301 MW of peak load management. In 2017, PacifiCorp began amortizing Utah DSM program costs over a 10-year period as a result of the approved Senate Bill 115, "Sustainable Transportation and Energy Plan Act." In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed, depending on the customers' actual loads. Recovery of the costs associated with the large industrial load management program are captured in the retail special contract agreements with those customers approved by their respective state commissions or through PacifiCorp's general rate case process.

Employees

As of December 31, 2017, PacifiCorp had approximately 5,500 employees, of which approximately 3,200 were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the International Brotherhood of Boilermakers.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

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

MidAmerican Funding and MHC

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

MidAmerican Funding'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. MidAmerican Funding was formed as a limited liability company in 1999 under the laws of the state of Iowa.

MidAmerican Energy

General

MidAmerican Energy, an indirect wholly owned subsidiary of BHE, is a United States regulated electric and natural gas utility company that serves 0.8 million retail electric customers in portions of Iowa, Illinois and South Dakota and 0.8 million retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy's service territory covers approximately 11,000 square miles. Metropolitan areas in which MidAmerican Energy distributes electricity at retail include Council Bluffs, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; and the Quad Cities (Davenport and Bettendorf, Iowa and Rock Island, Moline and East Moline, Illinois). Metropolitan areas in which it distributes natural gas at retail include Cedar Rapids, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities; and Sioux Falls, South Dakota. MidAmerican Energy has a diverse customer base consisting of urban and rural residential customers and a variety of commercial and industrial customers. Principal industries served by MidAmerican Energy include electronic data storage; processing and sales of food products; manufacturing, processing and fabrication of primary metals, farm and other non-electrical machinery; 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 capacity, 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.

Prior to 2016, MidAmerican Energy also had nonregulated business activities consisting predominantly of competitive electricity and natural gas retail sales. On January 1, 2016, MidAmerican Energy transferred the assets and liabilities of its unregulated retail services business to MidAmerican Energy Services, LLC, a subsidiary of BHE.

MidAmerican Energy's monthly net income is affected by the seasonal impact of weather on electricity and natural gas sales, seasonal retail electricity prices and the timing of recognition of federal renewable electricity production tax credits related to MidAmerican Energy's wind-powered generating facilities. For 2017, 82% of MidAmerican Energy's annual net income was recorded in the months of June through September.

Financial information on MidAmerican Energy's segments of business is disclosed in MidAmerican Energy's Note 20 of Notes to Financial Statements in Item 8 of this Form 10-K.

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

	2017	2016	2015
Operating revenue:			
Regulated electric	75%	76%	74%
Regulated gas	25	24	26
	100%	100%	100%
Operating income:			
Regulated electric	86%	88%	86%
Regulated gas	14	12	14
	100%	100%	100%

MidAmerican Energy'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. MidAmerican Energy was incorporated under the laws of the state of Iowa as part of the July 1, 1995 merger of Iowa-Illinois Gas and Electric Company, Midwest Resources Inc. and Midwest Power Systems Inc. On December 1, 1996, MidAmerican Energy became, through a corporate reorganization, a wholly owned subsidiary of MHC Inc., formerly known as MidAmerican Energy Holdings Company.

Regulated Electric Operations

Customers

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

	2017		2016		2015	
Iowa	22,365	91%	21,766	91%	20,922	90%
Illinois	1,891	8	1,940	8	1,903	9
South Dakota	236	1	218	1	217	1
	24,492	100%	23,924	100%	23,042	100%

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

	2017		2016		2015	
GWh sold:						
Residential	6,207	18%	6,408	20%	6,166	19%
Commercial	3,761	11	3,812	12	3,806	12
Industrial	12,957	39	12,115	37	11,487	36
Other	1,567	5	1,589	5	1,583	5
Total retail	24,492	73	23,924	74	23,042	72
Wholesale	9,165	27	8,489	26	8,741	28
Total GWh sold	33,657	100%	32,413	100%	31,783	100%
Average number of retail customers (in thousands):						
Residential	662	86%	653	86%	646	86%
Commercial	92	12	91	12	90	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	770	100%	760	100%	752	100%

Variations in weather, economic conditions and various conservation and energy efficiency measures and programs can impact customer usage. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in MidAmerican Energy's electricity sales that are principally related to weather and the related use of electricity for air conditioning. Additionally, electricity sales are priced higher in the summer months compared to the remaining months of the year. As a result, 40% to 50% of MidAmerican Energy's regulated electric revenue is reported in the months of June, July, August and September.

A degree of concentration of sales exists with certain large electric retail customers. Sales to the ten largest customers, from a variety of industries, comprised 19%, 16% and 15% of total retail electric sales in 2017, 2016 and 2015, respectively. Sales to electronic data storage customers included in the ten largest customers comprised 9%, 7% and 5% of total retail electric sales in 2017, 2016 and 2015, respectively.

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 19, 2017, retail customer usage of electricity caused a new record hourly peak demand of 4,850 MW on MidAmerican Energy's electric distribution system, which is 98 MW greater than the previous 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, 2017:

Generating Facility	Location	Energy Source	Year Installed	Facility Net Capacity (MW)[1]	Net Owned Capacity (MW)[1]
WIND:					
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Century	Blairsburg, IA	Wind	2005-2008	200	200
Victory	Westside, IA	Wind	2006	99	99
Pomeroy	Pomeroy, IA	Wind	2007-2011	286	286
Adair	Adair, IA	Wind	2008	175	175
Carroll	Carroll, IA	Wind	2008	150	150
Charles City	Charles City, IA	Wind	2008	75	75
Walnut	Walnut, IA	Wind	2008	150	150
Laurel	Laurel, IA	Wind	2011	120	120
Rolling Hills	Massena, IA	Wind	2011	443	443
Eclipse	Adair, IA	Wind	2012	200	200
Morning Light	Adair, IA	Wind	2012	100	100
Vienna	Gladbrook, IA	Wind	2012-2013	150	150
Lundgren	Otho, IA	Wind	2014	250	250
Macksburg	Macksburg, IA	Wind	2014	119	119
Wellsburg	Wellsburg, IA	Wind	2014	139	139
Adams	Lennox, IA	Wind	2015	150	150
Highland	Primghar, IA	Wind	2015	475	475
Ida Grove	Ida Grove, IA	Wind	2016	300	300
O'Brien	Primghar, IA	Wind	2016	250	250
Beaver Creek	Ogden, IA	Wind	2017	170	170
Prairie	Montezuma, IA	Wind	2017	164	164
				4,341	4,341
COAL:					
Louisa	Muscatine, IA	Coal	1983	744	655
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	712	563
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	810	483
Ottumwa	Ottumwa, IA	Coal	1981	730	380
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	512	368
George Neal Unit No. 4	Salix, IA	Coal	1979	663	269
				4,171	2,718
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	488	488
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	182	182
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	167	167
Sycamore	Johnston, IA	Gas or Oil	1974	148	148
River Hills	Des Moines, IA	Gas	1966-1967	113	113
Riverside Unit No. 5	Bettendorf, IA	Gas	1961	113	113
Coralville	Coralville, IA	Gas	1970	63	63
Moline	Moline, IL	Gas	1970	61	61
28 portable power modules	Various	Oil	2000	56	56
Parr	Charles City, IA	Gas	1969	33	33
				1,424	1,424
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,820	455
HYDROELECTRIC:					
Moline Unit Nos. 1-4	Moline, IL	Hydroelectric	1941	4	4
Total Available Generating Capacity				11,760	8,942
PROJECTS UNDER CONSTRUCTION					
Various wind projects				1,666	1,666
				13,426	10,608

(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.

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

	2017	2016	2015
Coal	40%	39%	48%
Nuclear	11	12	12
Natural gas	1	2	1
Wind and other(1)	38	35	29
Total energy generated	90	88	90
Energy purchased - short-term contracts and other	8	10	8
Energy purchased - long-term contracts (renewable)(1)	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 and reliably operate its electric system. 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. MidAmerican Energy evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, MidAmerican Energy places 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. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction.

Coal

All of the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities through 2019. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. MidAmerican Energy's coal supply portfolio has substantially all of its expected 2018 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio.

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

Nuclear

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"), a subsidiary of Exelon Corporation, is the 75% joint owner and the operator of Quad Cities Station. Approximately one-third of the nuclear fuel assemblies in each reactor core at Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that the following requirements for Quad Cities Station can be met under existing supplies or commitments: uranium requirements through 2021 and partial requirements through 2025; uranium conversion requirements through 2021 and partial requirements through 2025; enrichment requirements through 2021 and partial requirements through 2025; and fuel fabrication requirements through 2022. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate it will have difficulty in contracting for uranium, uranium conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station during these time periods.

Natural Gas

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.

Wind and Other

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, 2017, are authorized to earn over their regulatory lives a fixed rate of return on equity ranging from 11.0% to 12.2% on the cost of their original construction, which excludes the cost of later replacements, in any future Iowa rate proceeding. MidAmerican Energy's wind-powered generating facilities, including those facilities where a significant portion of the equipment was replaced, commonly referred to as repowered 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 2027. In 2017, certain of MidAmerican Energy's wind-powered generating facilities for which production tax credits had previously expired were repowered.

Of the 4,388 MW (nominal ratings) of wind-powered generating facilities in-service as of December 31, 2017, 3,642 MW were generating production tax credits. Production tax credits earned by MidAmerican Energy's wind-powered generating facilities placed in-service prior to 2013, except for facilities that have been repowered, are included in ECAMs, through which MidAmerican Energy is allowed to recover fluctuations in its electric retail energy costs. Facilities earning production tax credits that currently benefit customers through ECAMs totaled 1,624 MW (nominal ratings) as of December 31, 2017. In 2017, MidAmerican Energy earned $287 million of production tax credits, 47% of which was included in ECAMs.

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

MidAmerican Energy's total net generating capability accredited by the MISO for the summer of 2017 was 5,410 MW compared to a 2017 summer peak demand of 4,850 MW. Accredited net generating capability represents the amount of generation available to meet the requirements of MidAmerican Energy's retail customers and consists of MidAmerican Energy-owned generation, certain customer private generation that MidAmerican Energy is contractually allowed to dispatch and the net amount of capacity purchases and sales. Accredited capacity may vary from the nominal, or design, capacity ratings, particularly for wind turbines whose output is dependent upon wind levels at any given time. Additionally, the actual amount of generating capacity available at any time may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. MidAmerican Energy's accredited capability currently exceeds the MISO's minimum requirements.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 4,000 miles of transmission lines in four states, 37,500 miles of distribution lines and 380 substations as of December 31, 2017. 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 capacity, energy and ancillary services markets as a transmission-owning member and, accordingly, operates its transmission assets at the direction of the MISO. The MISO manages its energy and ancillary service markets using reliability-constrained economic dispatch of the region's generation. For both the day-ahead and real-time (every five minutes) markets, the MISO analyzes generation commitments to provide market liquidity and transparent pricing while maintaining transmission system reliability by minimizing congestion and maximizing efficient energy transmission. Additionally, through its FERC-approved open access transmission tariff ("OATT"), the MISO performs the role of transmission service provider throughout the MISO footprint and administers the long-term planning function. MISO and related costs of the participants are shared among the participants through a number of mechanisms in accordance with the MISO tariff.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in its service territory. MidAmerican Energy purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the gas to MidAmerican Energy's service territory and for storage and balancing services. MidAmerican Energy sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for end-use customers who have independently secured their supply of natural gas. During 2017, 55% of the total natural gas delivered through MidAmerican Energy's distribution system was associated with transportation service.

Natural gas property consists primarily of natural gas mains and services lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of MidAmerican Energy included 23,500 miles of natural gas main and service lines as of December 31, 2017.

Customer Usage and Seasonality

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

	2017	**2016**	**2015**
Iowa	76%	76%	76%
South Dakota	13	13	13
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

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

	2017	2016	2015
Residential	41%	41%	42%
Commercial(1)	20	21	21
Industrial(1)	4	4	5
Total retail	65	66	68
Wholesale(2)	35	34	32
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	114,298	113,294	110,105
Total Dth of transportation service (in thousands)	92,136	83,610	80,001
Total average number of retail customers (in thousands)	751	742	733

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

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

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

On January 6, 2014, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,281,767 Dth. This peak-day delivery consisted of 69% traditional retail sales service and 31% transportation service. MidAmerican Energy's 2017/2018 winter heating season peak-day delivery as of February 2, 2018, was 1,244,354 Dth reached on January 15, 2018. This preliminary peak-day delivery included 66% traditional retail sales service and 34% 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, and the use of financial derivatives to fix the price on a portion of the anticipated natural gas requirements of MidAmerican Energy's customers. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of the purchased gas adjustment clauses ("PGA").

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

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

MidAmerican Energy utilizes natural gas storage leased from the interstate pipelines to meet retail customer requirements, manage fluctuations in demand due to changes in weather and other usage factors and manage variation in seasonal natural gas pricing. MidAmerican Energy typically withdraws natural gas from storage during the heating season when customer demand is historically at its peak and injects natural gas into storage during off-peak months when customer demand is historically lower. MidAmerican Energy also utilizes its three LNG facilities to meet peak day demands during the winter heating season. The leased storage and LNG facilities reduce MidAmerican Energy's dependence on natural gas purchases during the volatile winter heating season and can deliver a significant portion of MidAmerican Energy's anticipated retail sales requirements on a peak winter day. For MidAmerican Energy's 2017/2018 winter heating season preliminary peak-day of January 15, 2018, supply sources used to meet deliveries to traditional retail sales service customers included 53% from purchases from interstate pipelines, 39% from leased storage and 8% from MidAmerican Energy's LNG facilities.

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

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

Demand-side Management

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and gas customers since 1990 and to customers in its other jurisdictions since 2008. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, MidAmerican Energy offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by all retail electric and gas customers. In 2017, $147 million was expensed for MidAmerican Energy's DSM programs, which resulted in estimated first-year energy savings of 311,000 MWh of electricity and 774,000 Dth of natural gas and an estimated peak load reduction of 464 MW of electricity and 9,244 Dth per day of natural gas.

Employees

As of December 31, 2017, MidAmerican Funding and its subsidiaries, which includes MidAmerican Energy, had approximately 3,300 employees, of which approximately 1,400 were covered by union contracts. MidAmerican Energy has three separate contracts with locals of the International Brotherhood of Electrical Workers ("IBEW") and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union. A contract with the IBEW covering substantially all of the union employees expires April 30, 2022.

NV ENERGY (NEVADA POWER AND SIERRA PACIFIC)

General

NV Energy, an indirect wholly owned subsidiary of BHE acquired on December 19, 2013, is an energy holding company headquartered in Nevada whose principal subsidiaries are Nevada Power and Sierra Pacific. Nevada Power and Sierra Pacific are indirect consolidated subsidiaries of Berkshire Hathaway. Nevada Power is a United States regulated electric utility company serving 0.9 million retail customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. Sierra Pacific is a United States regulated electric and natural gas utility company serving 0.3 million retail electric customers and 0.2 million retail and transportation natural gas customers in northern Nevada. The Nevada Utilities are principally engaged in the business of generating, transmitting, distributing and selling electricity and, in the case of Sierra Pacific, in distributing, selling and transporting natural gas. Nevada Power and Sierra Pacific have electric service territories covering approximately 4,500 square miles and 41,200 square miles, respectively. Sierra Pacific has a natural gas service territory covering approximately 900 square miles in Reno and Sparks. Principal industries served by the Nevada Utilities include gaming, recreation, warehousing, manufacturing and governmental. Sierra Pacific also serves the mining industry. The Nevada Utilities buy and sell electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize economic benefits of electricity generation, retail customer loads and wholesale transactions.

The Nevada Utilities' electric and natural gas operations are conducted under numerous nonexclusive franchise agreements, revocable permits and licenses obtained from federal, state and local authorities. The expiration of these franchise agreements ranges from 2020 through 2032 for Nevada Power and 2018 through 2049 for Sierra Pacific. The Nevada Utilities operate under certificates of public convenience and necessity as regulated by the PUCN, and as such the Nevada Utilities have an obligation to provide electricity service to those customers within their service territory. In return, the PUCN has established rates on a cost-of-service basis, which are designed to allow the Nevada Utilities an opportunity to recover all prudently incurred costs of providing services and an opportunity to earn a reasonable return on their investment.

NV Energy's monthly net income is affected by the seasonal impact of weather on electricity and natural gas sales and seasonal retail electricity prices from the Nevada Utilities'. For 2017, 82% of NV Energy annual net income was recorded in the months of June through September.

Regulated electric utility operation is Nevada Power's only segment while regulated electric utility operations and regulated natural gas operations are the two segments of Sierra Pacific. Financial information on Sierra Pacific's segments of business is disclosed in Sierra Pacific's Note 15 of Notes to Financial Statements in Item 8 of this Form 10-K.

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

	2017	2016	2015
Operating revenue:			
Electric	88%	86%	86%
Gas	12	14	14
	100%	100%	100%
Operating income:			
Electric	89%	89%	91%
Gas	11	11	9
	100%	100%	100%

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

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

Regulated Electric Operations

Customers

The Nevada Utilities' sell electricity to retail customers in a single state jurisdiction. Electricity sold to the Nevada Utilities' retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2017		2016		2015	
Nevada Power:						
GWh sold:						
Residential	9,501	42%	9,394	42%	9,246	41%
Commercial	4,656	20	4,663	21	4,635	21
Industrial	6,201	28	7,313	32	7,571	34
Other	212	1	212	1	214	1
Total fully bundled	20,570	91	21,582	96	21,666	97
DOS	1,830	8	662	3	407	2
Total retail	22,400	99	22,244	99	22,073	99
Wholesale	314	1	258	1	353	1
Total GWh sold	22,714	100%	22,502	100%	22,426	100%
Average number of retail customers (in thousands):						
Residential	810	88%	796	88%	782	88%
Commercial	106	12	105	12	104	12
Industrial	2	—	2	—	2	—
Total	918	100%	903	100%	888	100%
Sierra Pacific:						
GWh sold:						
Residential	2,492	24%	2,375	23%	2,315	23%
Commercial	2,954	28	2,933	28	2,942	29
Industrial	3,176	30	3,014	30	2,973	29
Other	16	—	16	—	16	—
Total fully bundled	8,638	82	8,338	81	8,246	81
DOS	1,394	13	1,360	13	1,304	13
Total retail	10,032	95%	9,698	94%	9,550	93%
Wholesale	561	5	662	6	664	7
Total GWh sold	10,593	100%	10,360	100%	10,214	100%
Average number of retail customers (in thousands):						
Residential	295	86%	291	86%	288	86%
Commercial	47	14	47	14	46	14
Total	342	100%	338	100%	334	100%

Variations in weather, economic conditions, particularly for gaming, mining and wholesale customers and various conservation, energy efficiency and private generation measures and programs can impact customer usage. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

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

The annual hourly peak customer demand on the Nevada Utilities' electric systems occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On June 20, 2017, customer usage of electricity caused an hourly peak demand of 5,929 MW on Nevada Power's electric system, which is 195 MW less than the record hourly peak demand of 6,124 MW set July 28, 2016. On August 1, 2017, customer usage of electricity caused an hourly peak demand of 1,824 MW on Sierra Pacific's electric system, which is 18 MW less than the record hourly peak demand of 1,842 MW set July 28, 2016.

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, 2017:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
Nevada Power:					
NATURAL GAS:					
Clark	Las Vegas, NV	Natural gas	1973-2008	1,102	1,102
Lenzie	Las Vegas, NV	Natural gas	2006	1,102	1,102
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	628	628
Higgins	Primm, NV	Natural gas	2004	530	530
Silverhawk	Las Vegas, NV	Natural gas	2004	520	520
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				4,364	4,364
COAL:					
Navajo Unit Nos. 1, 2 and 3(2)	Page, AZ	Coal	1974-1976	2,250	255
RENEWABLES:					
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
Nellis	Las Vegas, NV	Solar	2015	15	15
				20	20
Total Nevada Power				6,634	4,639
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	753	753
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	226	226
Clark Mountain	Sparks, NV	Natural gas	1994	132	132
				1,111	1,111
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
Total Sierra Pacific				1,633	1,372
Total NV Energy				8,267	6,011

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

(2) Nevada Power currently anticipates retiring Navajo Unit Nos. 1, 2 and 3 on or before December 2019. Refer to "Environmental Laws and Regulations" in Item 1 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:

	2017	2016	2015
Nevada Power:			
Natural gas	61%	64%	65%
Coal	7	7	7
Total energy generated	68	71	72
Energy purchased - long-term contracts (non-renewable)	15	14	15
Energy purchased - long-term contracts (renewable)(1)	15	14	12
Energy purchased - short-term contracts and other	2	1	1
	100%	100%	100%
Sierra Pacific:			
Natural gas	44%	45%	41%
Coal	5	8	13
Total energy generated	49	53	54
Energy purchased - long-term contracts (non-renewable)	38	36	36
Energy purchased - long-term contracts (renewable)(1)	11	10	9
Energy purchased - short-term contracts and other	2	1	1
	100%	100%	100%

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

The Nevada Utilities are required to have resources available to continuously meet their customer needs and reliably operate their electric systems. 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 place more reliance on other energy sources. As long as the Nevada Utilities' purchases are deemed prudent by the PUCN, through their annual prudency review, the Nevada Utilities are permitted to recover the cost of fuel and purchased power. The Nevada Utilities also have the ability to reset quarterly BTER, with PUCN approval, based on the last twelve months fuel costs and purchased power and to reset quarterly DEAA.

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

The Nevada Utilities have entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing renewable resources, natural gas and coal. Nevada Power has entered into contracts with a total capacity of 1,620 MW with contract termination dates ranging from 2022 to 2067. Included in these contracts are 1,360 MW of capacity of renewable energy, of which 100 MW of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 703 MW with contract termination dates ranging from 2018 to 2044. Included in these contracts are 512 MW of capacity of renewable energy, of which 200 MW of capacity are under development or construction and not currently available.

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

Natural Gas

The Nevada Utilities rely on first-of-the-month indexed physical gas purchases for the majority of natural gas needed to operate their generating facilities. To secure natural gas supplies for the generating facilities, the Nevada Utilities execute purchases pursuant to a PUCN approved four season laddering strategy. In 2017, natural gas supply net purchases averaged 326,215 and 141,188 Dth per day with the winter period contracts averaging 272,467 and 167,214 Dth per day and the summer period contracts averaging 364,141 and 122,702 Dth per day for Nevada Power and Sierra Pacific, respectively. The Nevada Utilities believe supplies from these sources are presently adequate and available to meet its needs.

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

Coal

Other than the agreement mentioned below for the Navajo Generating Station, the Nevada Utilities have no commitments to purchase coal for 2018 or beyond and will rely on spot market solicitations for any coal supplies needed during 2018 and will regularly monitor the western coal market for opportunities to meet these needs. Nevada Power eliminated Reid Gardner Unit No. 4's coal pile in March 2017. The Nevada Utilities have transportation services contracts with Union Pacific Railroad Company to ship coal from various origins in Central Utah, Western Colorado and Wyoming that expired December 31, 2017 for Nevada Power and expire December 31, 2019 for Sierra Pacific. The Navajo Generating Station, jointly owned by Nevada Power along with other entities and operated by Salt River Project, has a coal purchase agreement that extends through December 2019.

Transmission and Distribution

The Nevada Utilities' transmission system is part of the Western Interconnection, a regional grid in the United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The Nevada Utilities' transmission system, together with contractual rights on other transmission systems, enables the Nevada Utilities to integrate and access generation resources to meet their customer load requirements. Nevada Power's transmission and distribution systems included approximately 2,000 miles of transmission lines, 25,000 miles of distribution lines and 210 substations as of December 31, 2017. Sierra Pacific's transmission and distribution systems included approximately 2,300 miles of transmission lines, 17,700 miles of distribution lines and 200 substations as of December 31, 2017.

ON Line is a 231 mile, 500-kV transmission line connecting Nevada Power's and Sierra Pacific's service territories. ON Line provides the ability to jointly dispatch energy throughout Nevada and provide access to renewable energy resources in parts of northern and eastern Nevada, which enhances the Nevada Utilities' ability to manage and optimize their generating facilities. ON Line provides between 600 and 800 MW of transfer capability with interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Nevada Power system. ON Line was a joint project between the Nevada Utilities and Great Basin Transmission, LLC. The Nevada Utilities own a 25% interest in ON Line and have entered into a long-term transmission use agreement with Great Basin Transmission, LLC for its 75% interest in ON Line until 2054. The Nevada Utilities share of its 25% interest in ON Line and the long-term transmission use agreement is split 95% for Nevada Power and 5% for Sierra Pacific.

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

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. Costs incurred to complete projects approved through the IRP process still remain subject to review for reasonableness by the PUCN.

Nevada Power filed its triennial IRP in July 2015 and received PUCN approval in December 2015. Nevada Power filed an amended IRP in August 2016 and received PUCN approval in December 2016. Sierra Pacific filed its triennial IRP in July 2016 and received PUCN approval in December 2016. As a part of the filings, the Nevada Utilities sought PUCN authorization to acquire the South Point Energy Center, a 504-MW combined-cycle generating facility located in Arizona. In December 2016, the PUCN denied the acquisition of this facility. In January 2017, Nevada Power filed a petition for reconsideration relating to the acquisition of South Point Energy Center. In February 2017, the PUCN affirmed the denial of the acquisition of South Point Energy Center. The Nevada Utilities amended their respective IRPs in November 2017, requesting approval of three long-term renewable purchase power contracts. Nevada law was modified in 2017 under Senate Bill 146 and for future filings requires Nevada Power and Sierra Pacific to file jointly.

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

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

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

The energy supply plan operates in conjunction with the PUCN-approved 20-year IRP. It serves as a guide for near-term execution and fulfillment of energy needs. In September 2017, the Nevada Utilities filed updates to their respective energy supply plans seeking PUCN authorization to implement a laddering strategy for the procurement of short-term energy and capacity to serve peak customer demand. The PUCN approved Sierra Pacific's laddering strategy in October 2017, and approved Nevada Power's laddering strategy in November 2017. When the energy supply plan calls for executing contracts of longer than three years, PUCN approval is required.

Energy-Efficiency Programs

The Nevada Utilities have provided a comprehensive set of energy efficiency, demand response and conservation programs to their Nevada electric customers. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy audits and customer education and awareness efforts that provide information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Nevada Utilities have offered rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Energy efficiency program costs are recovered through annual rates set by the PUCN, and adjusted based on the Nevada Utilities' annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2017, Nevada Power spent $39 million on energy efficiency programs, resulting in an estimated 191,836 MWh of electric energy savings and an estimated 224 MW of electric peak load management. During 2017, Sierra Pacific spent $11 million on energy efficiency programs, resulting in an estimated 57,502 MWh of electric energy savings and an estimated 18 MW of electric peak load management.

Regulated Natural Gas Operations

Sierra Pacific is engaged in the procurement, transportation and distribution of natural gas for customers in its service territory. Sierra Pacific purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the natural gas from the production areas to Sierra Pacific's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. Sierra Pacific sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2017, 11% of the total natural gas delivered through Sierra Pacific's distribution system was for transportation service.

Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of Sierra Pacific included 3,300 miles of natural gas mains and service lines as of December 31, 2017.

Customer Usage and Seasonality

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

	2017	2016	2015
Residential	53%	52%	49%
Commercial(1)	27	26	24
Industrial(1)	9	9	8
Total retail	89	87	81
Wholesale	11	13	19
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	19,313	17,677	17,600
Total Dth of transportation service (in thousands)	1,977	2,256	2,288
Total average number of retail customers (in thousands)	165	163	159

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

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

On January 6, 2017, Sierra Pacific recorded its highest peak-day natural gas delivery of 148,077 Dth, which is 15,497 Dth less than the record peak-day delivery of 163,574 Dth set on December 9, 2013. This peak-day delivery consisted of 94% traditional retail sales service and 6% transportation service.

Fuel Supply and Capacity

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

Employees

As of December 31, 2017, Nevada Power had approximately 1,400 employees, of which approximately 700 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

As of December 31, 2017, Sierra Pacific had approximately 1,000 employees, of which approximately 500 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

NORTHERN POWERGRID

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

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

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

The suppliers purchase electricity from generators, sell the electricity to end-user customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." During 2017, RWE Npower PLC and certain of its affiliates and British Gas Trading Limited represented 21% and 15%, respectively, of the total combined distribution revenue of the Northern Powergrid Distribution Companies. Variations in demand from end-users can affect the revenues that are received by the Northern Powergrid Distribution Companies in any year, but such variations have no effect on the total revenue that the Northern Powergrid Distribution Companies are allowed to recover in a price control period. Under- or over-recoveries against price-controlled revenues are carried forward into prices for future years.

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

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

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

	2017		2016		2015	
Northern Powergrid (Northeast) Limited:						
Residential	5,125	36%	5,227	36%	5,144	34%
Commercial(1)	1,782	13	2,222	15	2,417	16
Industrial(1)	7,134	50	6,963	48	7,160	48
Other	198	1	214	1	231	2
	14,239	100%	14,626	100%	14,952	100%
Northern Powergrid (Yorkshire) plc:						
Residential	7,509	36%	7,612	36%	7,574	35%
Commercial(1)	2,558	12	3,116	15	3,352	16
Industrial(1)	10,716	51	10,275	48	10,403	48
Other	268	1	290	1	299	1
	21,051	100%	21,293	100%	21,628	100%
Total electricity distributed	35,290		35,919		36,580	
Number of end-users (in thousands):						
Northern Powergrid (Northeast) Limited	1,603		1,602		1,597	
Northern Powergrid (Yorkshire) plc	2,301		2,301		2,294	
	3,904		3,903		3,891	

(1) The increase in industrial and decrease in commercial is largely due to an acceleration in the Great Britain-wide customer reclassifications which are in progress (as a result of Ofgem approved industry changes), negatively impacting commercial volumes by 700 GWhs in 2017 compared to 2016.

As of December 31, 2017, the Northern Powergrid Distribution Companies' combined electricity distribution network included 17,400 miles of overhead lines, 42,000 miles of underground cables and 750 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 west Texas to Michigan's Upper Peninsula. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, gas marketing companies and industrial and commercial users. Northern Natural Gas' pipeline system consists of two commercial segments. 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. The Market Area and Field Area are separated at a Demarcation Point ("Demarc"). 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 5.9 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and 1.3 Bcf per day to the West Texas area and over 79 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 1.0 Trillion Cubic Feet ("Tcf") of natural gas to its customers annually.

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

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

	2017		2016		2015	
Transportation:						
Market Area	$ 504	73%	$ 492	77%	$ 474	72%
Field Area - deliveries to Demarc	36	5	23	4	49	7
Field Area - other deliveries	50	8	41	6	35	6
Total transportation	590	86	556	87	558	85
Storage	71	10	69	11	62	10
Total transportation and storage revenue	661	96	625	98	620	95
Gas, liquids and other sales	28	4	11	2	36	5
Total operating revenue	$ 689	100%	$ 636	100%	$ 656	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, 2017, approximately 85% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2019 and over 78% beyond 2020. As of December 31, 2017, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is over eight years.

Northern Natural Gas' Field Area customers consist primarily of energy marketing companies and midstream companies, which take advantage of the price spread opportunities created between Field Area supply points and Demarc. In addition, there are a growing number of midstream customers that are delivering gas south in the Field Area to the 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 2020, 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 79 Bcf and over 2.2 Bcf per day of peak delivery capability. These storage facilities provide operational flexibility for the daily balancing of Northern Natural Gas' system and provide services to customers for their winter peaking and year-round load swing requirements.

Northern Natural Gas has 65.1 Bcf of firm storage contracts with its cost-based and market-based services. Firm storage contracts with cost-based rates, representing 57.1 Bcf, have an average remaining contract term of seven 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 ten 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 2017, Northern Natural Gas had three customers, including MidAmerican Energy, that each accounted for greater than 10% of its transportation and storage revenue and its ten largest customers accounted for 65% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements with terms from 2022 to 2034 to retain its three largest customers' volumes. The loss of any of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas.

Northern Natural Gas' extensive pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, has access to multiple major supply basins. Direct access is available from producers in the Anadarko, Permian and Hugoton basins, some of which have recently experienced increased production from shale and tight sands formations adjacent to Northern Natural Gas' pipeline. Since 2011, the pipeline has connected 1,985,000 Dth per day of supply access from the Wolfberry shale formation in west Texas and from the Granite Wash tight sands formations in the Texas panhandle and in Oklahoma. Additionally, Northern Natural Gas has interconnections with several interstate pipelines and several intrastate pipelines with receipt, delivery, or bi-directional capabilities. Because of Northern Natural Gas' location and multiple interconnections it is able to access natural gas from other key production areas, such as the Rocky Mountain and western Canadian basins. The Rocky Mountain basins are accessed through interconnects with Trailblazer Pipeline Company, Tallgrass Interstate Gas Transmission, LLC, Cheyenne Plains Gas Pipeline Company, LLC, Colorado Interstate Gas Company and Rockies Express Pipeline, LLC ("REX"). The western Canadian basins are accessed through interconnects with Northern Border Pipeline Company ("Northern Border"), Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("Viking"). This supply diversity and access to both stable and growing production areas provides significant flexibility to Northern Natural Gas' system and customers.

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

Kern River

Kern River, an indirect wholly owned subsidiary of BHE, owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River provided 26% of California's demand for natural gas in 2016. 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, or 2.1 Bcf, 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 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. 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.

Kern River's rates are based on a levelized rate design with recovery of 70% of the original investment during the initial long-term contracts ("Period One rates"). After expiration of the initial term, eligible customers have the option to elect service at rates ("Period Two rates") that are lower than Period One rates because they are designed to recover the remaining 30% of the original investment. To the extent that eligible customers elected not to contract for service at Period Two rates, the volumes are turned back and sold at market rates for varying terms. As of December 31, 2017, Kern River has sold 212,417 Dth per day of total turned back volume of 378,503 Dth per day with an average remaining contract term of nearly four years. The remaining turned back capacity is sold on a short-term basis at market rates. Of the customers that are eligible to take Period Two service beginning May 1, 2018, 40% elected to extend their contracts at maximum Period Two rates, with 233,000 Dth per day electing 10-year contracts and 39,000 Dth per day electing 15-year contracts.

As of December 31, 2017, approximately 87% of Kern River's design capacity of 2,166,575 Dth per day is contracted pursuant to long-term firm natural gas transportation service agreements, whereby Kern River receives natural gas on behalf of customers at designated receipt points and transports the natural gas on a firm basis to designated delivery points. In return for this service, each customer pays Kern River a fixed monthly reservation fee based on each customer's maximum daily quantity, which represents 94% of total operating revenue, and a commodity charge based on the actual amount of natural gas transported pursuant to its long-term firm natural gas transportation service agreements and Kern River's tariff.

These long-term firm natural gas transportation service agreements expire between March 2018 and April 2033 and have a weighted-average remaining contract term of over nine years. Kern River's customers include electric and natural gas distribution utilities, major oil and natural gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies and financial institutions. As of December 31, 2017, nearly 78% 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 2017, 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 has undergone a significant shift in supply sources. Production from conventional sources has declined while production from unconventional sources, such as shale gas, has increased. This shift has affected the supply patterns, the flows, the locational and seasonal natural gas price spreads and rates that can be charged on pipeline systems. The impact has varied 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 renewables, 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.

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

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

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

Northern Natural Gas expects the current level of Field Area contracting to Demarc 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 LLC, Colorado Interstate Gas Company, Overland Trails Transmission, LLC, Questar Pipeline LLC and Questar Overthrust Pipeline LLC; and storage facilities such as Ryckman Creek Resources, LLC and Clear Creek Storage Company, LLC. These interconnections, in addition to the direct interconnections to natural gas processing facilities in Wyoming and California, allow Kern River to access natural gas reserves in Colorado, northwestern New Mexico, Wyoming, Utah, California and the Western Canadian Sedimentary Basin.

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

BHE TRANSMISSION

AltaLink

ALP, an indirect wholly owned subsidiary of BHE acquired on December 1, 2014, is a regulated electric transmission-only company headquartered in Alberta, Canada serving approximately 85% of Alberta's population. ALP connects generation plants to major load centers, cities and large industrial plants throughout its 87,000 square mile service territory, which covers a diverse geographic area including most major urban centers in central and southern Alberta. ALP's transmission facilities, consisting of approximately 8,100 miles of transmission lines and 310 substations as of December 31, 2017, 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 16,000 miles of transmission. The AIES is interconnected to British Columbia's transmission system that links Alberta with the North American western interconnected system.

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

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

The AESO mandate is defined in the Electric Utilities Act and its regulations, and requires the AESO to assess both current and future needs of Alberta's interconnected electrical system. In July 2017, the AESO released the 2017 Long-Term Outlook ("LTO"), which is a forecast used as one input to guide the AESO in planning Alberta's transmission system. In January 2018, the AESO finalized and made available the 2017 Long-Term Transmission Plan ("LTP"). The 2017 LTP places increased focus on the evolving economy, policy changes and environmental initiatives, including renewable generation additions and the phase-out of coal-fueled generation whenever possible. The plan was developed with the goal of efficient utilization of existing and planned transmission systems in areas where high renewables potential exists, and timely addition of necessary new transmission developments. The AESO has forecast Alberta's electricity demand to grow at an annual rate of 0.9 percent until 2037. Future generation investments are expected to keep pace with load growth and coal-fueled generation replacements, as well as generation additions primarily through the Renewable Electricity Program. The 2017 LTP identifies 15 transmission developments across Alberta proposed over the next five years valued at approximately C$1 billion. Regulatory approval for all identified developments is still required.

BHE U.S. Transmission

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

BHE U.S. Transmission indirectly owns a 50% interest in ETT, along with subsidiaries of American Electric Power Company, Inc. ("AEP"). ETT owns and operates electric transmission assets in the ERCOT and, as of December 31, 2017, had total assets of $3.0 billion. ETT is regulated by the Public Utility Commission of Texas. A total of $2.9 billion of transmission projects were in-service as of December 31, 2017, with $0.2 billion of projects forecast to be completed in 2018 through 2021. ETT's transmission system includes approximately 1,200 miles of transmission lines and 36 substations as of December 31, 2017.

BHE U.S. Transmission also indirectly owns a 25% interest in Prairie Wind Transmission, LLC, a joint venture with AEP and Westar Energy, Inc., to build, own and operate a 108-mile, 345 kV transmission project in Kansas. The project cost $158 million and was fully placed in-service in November 2014.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects that are in-service or under construction in the United States and in the Philippines. The following table presents certain information concerning these independent power projects as of December 31, 2017:

Generating Facility	Location	Energy Source	Installed	Power Purchase Agreement Expiration	Power Purchaser[1]	Facility Net Capacity (MW)[2]	Net Owned Capacity (MW)[2]
SOLAR:							
Topaz	California	Solar	2013-2014	2040	PG&E	550	550
Solar Star 1	California	Solar	2013-2015	2035	SCE	310	310
Solar Star 2	California	Solar	2013-2015	2035	SCE	276	276
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
Community Solar Gardens[6]	Minnesota	Solar	2016-2017	2041-2042	(5)	74	74
Alamo 6	Texas	Solar	2017	2042	CPS	110	110
Pearl	Texas	Solar	2017	2042	CPS	50	50
						1,660	1,512
WIND:							
Bishop Hill II	Illinois	Wind	2012	2032	Ameren	81	81
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Pinyon Pines II	California	Wind	2012	2035	SCE	132	132
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
Marshall	Kansas	Wind	2016	2036	MJMEC, KPP, KMEA & COIMO	72	72
Grand Prairie	Nebraska	Wind	2016	2036	OPPD	400	400
						1,153	1,153
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	2019	TEMUS	245	196
Power Resources	Texas	Natural Gas	1988	2018	EDF	212	212
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
Cordova	Illinois	Natural Gas	2001	2019	EGC	512	512
						1,019	970
Total Available Generating Capacity						4,330	4,111
PROJECTS UNDER CONSTRUCTION:							
Community Solar Gardens	Minnesota	Solar	2018	2043	(5)	24	24
Walnut Ridge	Illinois	Wind	2018	2028	USGSA	212	212
						236	236
						4,566	4,347

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

(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) The majority of the Imperial Valley Projects' Contract Capacity is currently sold to Southern California Edison Company under long-term power purchase agreements expiring in 2018 through 2026. Certain long-term power purchase agreement renewals have been entered into with other parties that begin upon the existing contracts' expiration and expire in 2039.

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

(5) The power purchasers are commercial, industrial and not-for-profit organizations.

(6) The community solar gardens project is consolidated in the table above for convenience as it consists of 74 distinct entities that each own an approximately 1 MW solar garden with independent but substantially similar terms and conditions.

Additionally, BHE Renewables has invested $1.2 billion in seven wind projects sponsored by third parties, commonly referred to as tax equity investments.

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

	2017	2016	2015
Solar	52%	49%	52%
Wind	17	19	14
Geothermal	19	20	23
Hydro	6	4	3
Natural gas	6	8	8
Total operating revenue	100	100%	100%

HOMESERVICES

HomeServices, a majority-owned subsidiary of BHE, is the second-largest 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 nearly 840 offices in 30 states and the District of Columbia with nearly 41,000 real estate agents under 42 brand names. The United States residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions. In October 2014, HomeServices acquired the remaining 50.1% of HomeServices Lending, a mortgage origination company.

In October 2012, HomeServices acquired a 66.7% interest in one of the largest residential real estate brokerage franchise networks in the United States, which offers and sells independently owned and operated residential real estate brokerage franchises. The noncontrolling interest member has the right to put the remaining 33.3% interest in the franchise business to HomeServices after March 2015 and HomeServices has the right to call the remaining 33.3% interest in the franchise business after completion and receipt of the 2017 financial statement audit at an option exercise formula based on historical financial performance.

HomeServices' franchise network currently includes over 365 franchisees in over 1,500 brokerage offices in 47 states with over 48,000 real estate agents under three brand names. In exchange for certain fees, HomeServices provides the right to use the Berkshire Hathaway HomeServices, Prudential or Real Living brand names and other related service marks, as well as providing orientation programs, training and consultation services, advertising programs and other services.

OTHER ENERGY BUSINESSES

Effective January 1, 2016, MidAmerican Energy Company transferred its nonregulated energy operations to MidAmerican Energy Services, LLC ("MES"), a subsidiary of BHE. MES is a nonregulated energy business consisting of competitive electricity and natural gas retail sales. MES' electric operations predominantly include sales to retail customers in Illinois, Texas, Ohio, Maryland and other states that allow customers to choose their energy supplier. MES' natural gas operations predominantly include sales to retail customers in Iowa and Illinois. Electricity and natural gas are purchased from producers and third party energy marketing companies and sold directly to commercial, industrial and governmental end-users. MES does not own electricity or natural gas production assets but hedges its contracted sales obligations either with physical supply arrangements or financial products. As of December 31, 2017, MES' contracts in place for the sale of electricity totaled 19,225 GWh with a weighted average life of 2.1 years and for the sale of natural gas totaled 28,605,700 Dth with a weighted average life of 1.3 years. In addition, MES 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. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

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

	2017	2016	2015
Illinois	46%	48%	51%
Ohio	23	21	18
Texas	15	13	15
Maryland	7	7	7
Other	9	11	9
	100%	100%	100%

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

	2017	2016	2015
Iowa	86%	86%	87%
Illinois	9	9	8
Other	5	5	5
	100%	100%	100%

GENERAL REGULATION

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

Domestic Regulated Public Utility Subsidiaries

The Utilities are subject to comprehensive regulation by various state, federal 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 the 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, (b) the utility's level of investment and (c) changes in income tax laws. 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. In certain jurisdictions, the utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

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

With certain limited exceptions, the Utilities have an exclusive right to serve retail customers within their service territories and, in turn, have an obligation to provide service to those customers. In some jurisdictions, certain classes of customers may choose to purchase all or a portion of their energy from alternative energy suppliers, and in some jurisdictions retail customers can generate all or a portion of their own energy. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, nonresidential customers have the right to choose an alternative provider of energy supply. The impact of this right on PacifiCorp's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC. In Illinois, state law has established a competitive environment so that all Illinois customers are free to choose their retail service supplier. For customers that choose an alternative retail energy supplier, MidAmerican Energy continues to have an ongoing obligation to deliver the supplier's energy to the retail customer. MidAmerican Energy bills the retail customer for such delivery services. MidAmerican Energy also has an obligation to serve customers at regulated cost-based rates and has a continuing obligation to serve customers who have not selected a competitive electricity provider. The impact of this right on MidAmerican Energy's financial results has not been material. 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, all as determined by the PUCN. Also, the Utilities and the state regulatory commissions are individually evaluating how best to integrate private 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 to participate in the incentive natural gas rate tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose its source of natural gas. In addition, natural gas customers using greater than 1,000 therms per day have the ability to secure their own natural gas supplies under the gas transportation tariff.

PacifiCorp

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

State Regulator	Base Rate Test Period	Adjustment Mechanism
UPSC	Forecasted or historical with known and measurable changes(1)	EBA under which 100% (beginning in June 2016) of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Wheeling revenue is also included in the mechanism. Prior to June 2016, the amount deferred was 70% of the difference as noted above.
		Balancing account to provide for 100% recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues after adjusting for a REC incentive authorized by the UPSC.
		Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
OPUC	Forecasted	PCAM under which 90% of the difference between forecasted net variable power costs and production tax credits established under the annual TAM and actual net variable power costs and production tax credits is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs and production tax credits must fall outside of an established asymmetrical deadband range and is also subject to an earnings test.
		Annual TAM based on forecasted net variable power costs and production tax credits. Production tax credits were not included in forecasted net variable power costs prior to 2017.
		Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission costs that are not reflected in general rates.
		Balancing account for proceeds from the sale of RECs.
WPSC	Forecasted or historical with known and measurable changes(1)	ECAM under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Chemical costs and start-up fuel costs are also included in the mechanism starting in 2016.
		REC and sulfur dioxide revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and sulfur dioxide revenues and the level in rates.
WUTC	Historical with known and measurable changes	PCAM under which the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates after applying a $4 million deadband for positive or negative net power cost variances. For net power cost variances between $4 million and $10 million, amounts to be recovered from customers are allocated 50/50 and amounts to be credited to customers are allocated 75/25 (customers/PacifiCorp). Positive or negative net power cost variances in excess of $10 million are allocated 90/10 (customers/PacifiCorp).
		Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates.
		REC revenue tracking mechanism to provide credit of 100% of Washington-allocated REC revenues.
		Decoupling mechanism under which the difference between actual annual revenues and authorized revenues per customer is deferred and reflected in future rates, subject to an earnings test. To trigger a rate adjustment, the deferral balance must exceed plus or minus 2.5% of the authorized revenue at the end of each deferral period by rate class. Rate adjustments must not exceed a surcharge of 5% of the actual normalized revenue by class.
IPUC	Historical with known and measurable changes	ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference between the level of REC revenues included in base rates and actual REC revenues and differences in actual production tax credits compared to the amount in base rates.
CPUC	Forecasted	PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service.
		ECAC that allows for an annual update to actual and forecasted net power costs.
		PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net power costs.

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

MidAmerican Energy

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

Iowa law also permits rate-regulated utilities to seek ratemaking principles with the IUB prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUB ratemaking principles orders for a 484-MW (MidAmerican Energy's share) coal-fueled generating facility, a 495-MW combined cycle natural gas-fueled generating facility and 6,048 MW (nominal ratings) of wind-powered generating facilities, including 1,666 MW (nominal ratings) under construction, as of December 31, 2017. These ratemaking principles established cost caps for the projects and authorized a fixed rate of return on equity for the respective generating facilities over the regulatory life of the facilities in any future Iowa rate proceeding. As of December 31, 2017, the generating facilities in service totaled $5.9 billion, or 42%, of MidAmerican Energy's regulated property, plant and equipment, net and were subject to these ratemaking principles at a weighted average return on equity of 11.7% with a weighted average remaining life of 31 years.

Under its current Iowa, Illinois and South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its retail electric sales 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, except for production tax credits earned by repowered facilities, which totaled 414 MW as of December 31, 2017. Eligibility for production tax credits associated with MidAmerican Energy's earliest projects began expiring in 2014. Additionally, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in all jurisdictions. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions.

Of the wind-powered generating facilities placed in-service as of December 31, 2017, 2,097 MW (nominal ratings) have not been included in the determination of MidAmerican Energy's Iowa retail electric base rates. In accordance with the related ratemaking principles, until such time as these generation assets are reflected in base rates and ceasing thereafter, MidAmerican Energy reduced its revenue from Iowa energy adjustment clause recoveries by $5 million in 2015 and $9 million in 2016 and is to reduce its recoveries by $12 million for each calendar year thereafter.

MidAmerican Energy has mechanisms in Iowa where rate base may be reduced, including revenue sharing and retail customer benefits attributable to most of the wind-powered generating facilities placed in-service in 2016 ("Wind X"). The revenue sharing mechanism originates from multiple ratemaking principles proceedings and reduces rate base for Iowa electric returns on equity exceeding an established benchmark. The Wind X customer benefit mechanism reduces rate base for the value of higher cost retail energy displaced by Wind X production.

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

NV Energy (Nevada Power and Sierra Pacific)

Rate Filings

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

Energy Choice Initiative - Deregulation

In November 2016, a majority of Nevada voters supported a ballot measure to amend Article 1 of the Nevada Constitution. If approved again in 2018, the proposed constitutional amendment would require the Nevada Legislature to create, on or before July 2023, an open and competitive retail electric market that includes provisions to reduce costs to customers, protect against service disconnections and unfair practices and prohibit the granting of monopolies and exclusive franchises for the generation of electricity. The outcome of any customer choice initiative could have broad implications to the Nevada Utilities. The Governor issued an executive order establishing the Governor's Committee on Energy Choice in which the Nevada Utilities have representation. The Nevada Utilities have been engaged in the legislative process before the Governor's committee and related proceedings before the PUCN and the legislature. The Nevada Utilities cannot assess or predict the outcome of the potential constitutional amendment or the financial impact, if any, at this time. The uncertainty created by the ballot initiative complicates both the short-term allocation of resources and long-term resource planning for the Nevada Utilities, including the ability to forecast load growth and the timing of resource additions. This uncertainty in planning is evidenced by a decision the PUCN issued denying Nevada Power's proposed purchase of the South Point Energy Center, citing the unknown outcomes of the Energy Choice Initiative as one of the factors considered in their decision.

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 $1.2 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. Much of the Utilities' wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility. As a result of a 2016 order from the FERC following BHE's acquisition of NV Energy, the Utilities are precluded from selling at market-based rates in the PacifiCorp-East, PacifiCorp-West, Idaho Power Company and NorthWestern Energy balancing authority areas. The Utilities had previously relinquished their market-based rate authority in the NV Energy balancing authority area. Wholesale electricity sales in those specific balancing authority areas are permitted at cost-based rates. On October 30, 2017, the FERC granted the application of PacifiCorp, Nevada Power and Sierra Pacific for authority to bid into the California EIM at market-based rates.

The Utilities' authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the Utilities are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. PacifiCorp, the Nevada Utilities and certain affiliates, representing the BHE Northwest Companies, file together for market power study purposes. The BHE Northwest Companies' most recent triennial filing was made in June 2016 and, as to its non-mitigated balancing authority areas, was approved in November 2017. MidAmerican Energy and certain affiliates file together for market power study purposes of the FERC-defined Northeast Region. The most recent triennial filing for the Northeast Region was made in June 2017 and an order accepting it was issued in January 2018. MidAmerican Energy and certain affiliates file together for market power study purposes of the FERC-defined Central Region. The most recent triennial filing for the Central Region was made in December 2017 and is currently pending with the FERC. Under the FERC's market-based rules, the Utilities must also file with the FERC a notice of change in status when there is a change in the conditions that the FERC relied upon in granting market-based rate authority.

Transmission

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

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

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

MidAmerican Energy has approval from the MISO to construct and own four Multi-Value Projects ("MVPs") located in Iowa and Illinois that will have added approximately 250 miles of 345 kV transmission line to MidAmerican Energy's transmission system since 2012, of which 224 miles have been placed in-service as of December 31, 2017. The MISO OATT allows for broad cost allocation for MidAmerican Energy's MVPs, including similar MVPs of other MISO participants. Accordingly, a significant portion of the revenue requirement associated with MidAmerican Energy's MVP investments will be shared with other MISO participants based on the MISO's cost allocation methodology, and a portion of the revenue requirement of the other participants' MVPs will be allocated to MidAmerican Energy. Additionally, MidAmerican Energy has approval from the FERC to include 100% of construction work in progress in the determination of rates for its MVPs and to use a forward-looking rate structure for all of its transmission investments and costs. The transmission assets and financial results of MidAmerican Energy's MVPs are excluded from the determination of its retail electric rates.

The FERC has established an extensive number of mandatory reliability standards developed by the NERC and the WECC, including planning and operations, critical infrastructure protection and regional standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC; the NERC; and the WECC for PacifiCorp, Nevada Power, and Sierra Pacific; and the Midwest Reliability Organization for MidAmerican Energy.

Hydroelectric

The FERC licenses and regulates the operation of hydroelectric systems, including license compliance and dam safety programs. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Under the Federal Power Act, 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 utilized by PacifiCorp in development of public safety programs consisting of a dam safety program and emergency action plans.

PacifiCorp's Klamath River hydroelectric system is the only significant hydroelectric system for which PacifiCorp has a pending relicensing process with the FERC. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath River hydroelectric system.

Nuclear Regulatory Commission

General

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

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

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

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

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

Nuclear Insurance

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

Exelon Generation purchases private market nuclear liability insurance for Quad Cities Station in the maximum available amount of $450 million, which includes coverage for MidAmerican Energy's ownership. In accordance with Price-Anderson, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the United States. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $64 million per incident, payable in installments not to exceed $10 million annually.

The insurance for nuclear property damage losses covers property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Exelon Generation purchases primary and excess property insurance protection for the combined interests in Quad Cities Station, with coverage limits for nuclear damage losses up to $1.5 billion and non-nuclear property damage losses up to $2.1 billion. MidAmerican Energy also directly purchases extra expense coverage for its share of replacement power and other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Exelon Generation, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments to be called upon based on the industry mutual board of directors' discretion for adverse loss experience. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total $9 million.

The master nuclear worker liability coverage, which is purchased by Exelon Generation for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of $450 million for the nuclear industry as a whole, which is in effect to cover tort claims of workers in nuclear-related industries.

United States Mine Safety

PacifiCorp's mining operations are regulated by the Federal Mine Safety and Health Administration, which administers federal mine safety and health laws and regulations, and state regulatory agencies. The Federal Mine Safety and Health Administration has the statutory authority to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay penalties or fines for violations of federal mine safety standards. Federal law requires PacifiCorp to have a written emergency response plan specific to each underground mine it operates, which is reviewed by the Federal Mine Safety and Health Administration every six months, and to have at least two mine rescue teams located within one hour of each mine. Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

Interstate Natural Gas Pipeline Subsidiaries

The Pipeline Companies are regulated by the FERC, pursuant to the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, (a) rates, charges, terms and conditions of service and (b) 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, 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"), the Pipeline Safety, Regulatory Certainty, Job Creation Act of 2011 ("2011 Act") and the Protecting Our Infrastructure Of Pipelines And Enhancing Safety Act Of 2016 ("2016 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 require recurring inspections of high consequence area segments every seven years after the initial baseline assessment which was completed by Kern River in early 2011 and Northern Natural Gas in 2012.

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 a number of notices of proposed rulemaking have been issued. The BHE Pipeline Group anticipates final rules on a number of areas sometime in 2018. The BHE Pipeline Group cannot currently assess the potential cost of compliance with new rules and regulations under the 2011 Act.

The 2016 Act required the Pipeline and Hazardous Materials Safety Administration to set federal minimum safety standards for underground natural gas storage facilities and authorized emergency order (interim final rule) authority. The Pipeline and Hazardous Materials Safety Administration issued an interim final rule requiring underground natural gas storage field operators to implement the requirements of the American Petroleum Institute ("API") Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs." Northern Natural Gas has three underground natural gas storage fields which fall under this regulation and has implemented programs to be in full compliance with this regulation. Kern River does not have underground natural gas storage facilities.

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

Northern Powergrid Distribution Companies

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

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

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

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

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

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

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

Under the price control, as revised by the CMA, and excluding the effects of incentive schemes and any deferred revenues from the prior price control, the base allowed revenue of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc decreased by approximately 1.0% and 0.5%, respectively, from 2015-16 to 2016-17, and then remains constant in all subsequent years within the price control period (RIIO-ED1) through 2022-23, before the addition of inflation. Nominal base allowed revenues will increase in line with inflation.

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

ALP Transmission

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

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

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

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

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

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

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

Independent Power Projects

The Yuma, Cordova, Saranac, Power Resources, Topaz, Agua Caliente, Solar Star, Bishop Hill II, Jumbo Road, Marshall, Grande Prairie, Pinyon Pines, Alamo 6 and Pearl independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act, while the Imperial Valley and Wailuku independent power projects are currently certified as Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs are generally exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities.

The Yuma, Cordova, Saranac, Imperial Valley, Topaz, Agua Caliente, Solar Star, Bishop Hill II, Marshall, Grande Prairie and Pinyon Pines independent power projects have obtained authority from the FERC to sell their power using market-based rates. This authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the respective independent power projects are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. The Pinyon Pines, Solar Star, Topaz and Yuma independent power projects and power marketer CalEnergy, LLC file together for market power study purposes of the FERC-defined Southwest Region. The most recent triennial filing for the Southwest Region was made in June 2016 and an order accepting it was issued December 2016. The Cordova and Saranac independent power projects and power marketer CalEnergy, LLC file together with MidAmerican Energy and certain affiliates for market power study purposes of the FERC-defined Northeast Region. The most recent triennial filing for the Northeast Region was made in June 2017 and an order accepting it was issued in January 2018. The Bishop Hill II independent power project and power marketer CalEnergy, LLC file together with MidAmerican Energy and certain affiliates for market power study purposes of the FERC-defined Central Region. The most recent triennial filing for the Central Region was made in December 2017 and is currently pending with the FERC.

The entire output of Jumbo Road, Alamo 6, Pearl and Power Resources is within the Electric Reliability Council of Texas ("ERCOT") and market-based authority is not required for such sales solely within ERCOT as the ERCOT market is not a FERC-jurisdictional market. Similarly, Wailuku sells its output solely to the Hawaii Electric Company within the Hawaii electric grid which is not a FERC-jurisdictional market and Wailuku therefore does not require market-based rate authority.

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

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

Residential Real Estate Brokerage Company

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

REGULATORY MATTERS

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

PacifiCorp

In June 2017, PacifiCorp filed two applications each with the UPSC, IPUC and the WPSC for the Energy Vision 2020 project. The first application sought approvals to construct or procure four new Wyoming wind resources with a total capacity of 860 MWs identified as benchmark resources and certain transmission facilities. A request for proposals was issued in September 2017 seeking up to 1,270 MWs to compete against PacifiCorp's benchmark resources in the final resource selection process for the project. PacifiCorp has identified four winning wind resource bids from this solicitation totaling 1,311 MWs, consisting of 1,111 MWs owned and 200 MW as a power-purchase agreement. The combined new wind and transmission projects will cost approximately $2 billion. Hearings are expected to be set by the WPSC, UPSC, and IPUC to occur in the second quarter of 2018. The second application sought approval of PacifiCorp's resource decision to upgrade or "repower" existing wind resources, as prudent and in the public interest. PacifiCorp estimates the wind repowering project will cost approximately $1 billion. Applications filed in Utah, Idaho, and Wyoming seek approval for the proposed rate-making treatment associated with the projects. The hearings on repowering in Utah and Wyoming have been extended to provide time for supplemental analyses for updated costs and the Tax Cuts and Jobs Act enacted on December 22, 2017 ("2017 Tax Reform") and are scheduled to occur in April and May 2018. On December 28, 2017, the IPUC approved an all-party stipulation for approval of the application to repower existing wind facilities and allow recovery of costs in rates through an adjustment to the annual ECAM filing.

The 2017 Tax Reform enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the U.S. federal corporate income tax rate from 35% to 21%. PacifiCorp has agreed to defer the impact of the tax law change with each of its state rate regulatory bodies. PacifiCorp will be proposing to reduce customer rates for a portion of the lower annual income tax expense resulting from the decrease in federal tax rates, and deferring the remainder to offset other costs as approved by the regulatory bodies. PacifiCorp cannot predict the timing or ultimate outcome of regulatory actions on its proposals.

Utah Mine Disposition

In December 2014, PacifiCorp filed an advice letter with the CPUC to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC. On February 6, 2017, a joint motion was filed with the CPUC seeking approval of a settlement agreement reached by PacifiCorp and all other parties. The agreement states, among other things, that the decision to sell certain Utah mining assets is in the public interest. Parties also reserve their rights to additional testimony, briefs and hearings to the extent the CPUC determines that additional California Environmental Quality Act proceedings are necessary. A CPUC decision on the joint motion and settlement agreement is expected in 2018.

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

Utah

In March 2017, PacifiCorp filed its annual EBA with the UPSC seeking approval to refund to customers $7 million in deferred net power costs for the period January 1, 2016 through December 31, 2016, reflecting the difference between base and actual net power costs in the 2016 deferral period. In April 2017, PacifiCorp revised its recommendation and requested approval to refund an additional $7 million to customers resulting in an interim rate reduction of $14 million. The rate change became effective on an interim basis May 1, 2017. In January 2018, the UPSC approved a stipulation that provides an additional $3 million reduction, which will be incorporated into the 2018 EBA filing to be made in March 2018.

In March 2017, PacifiCorp filed its annual REC balancing account application with the UPSC seeking to refund to customers $1 million for the period January 1, 2016 through December 31, 2016 for the difference in base and actual RECs. The rate change became effective on an interim basis June 1, 2017.

As a result of the Utah Sustainable Transportation and Energy Plan legislation that was signed into law in March 2016, PacifiCorp filed an application in September 2016 seeking approval of a proposed five-year pilot program with an annual budget of $10 million authorized under the legislation to address clean-coal technology programs, commercial line extension programs, an electric vehicle incentive program and associated residential time of use rate pilot and other programs authorized in legislation. The UPSC issued orders approving PacifiCorp's application in phases in December 2016, May 2017, June 2017 and October 2017.

In November 2016, PacifiCorp filed cost of service analyses, as ordered by the UPSC, to quantify the cost shifting due to net metering. The UPSC ordered the analyses to comply with a 2014 law requiring the examination of whether the costs of net metering exceed the benefits to PacifiCorp and other customers. The filing includes a proposal for a new rate schedule for residential customer generators with a three-part rate based on the cost of serving this class of customer, which will mitigate future cost shifting. PacifiCorp proposed that the new rate schedule only apply to new net metering customers that submit applications after December 9, 2016. On December 9, 2016, PacifiCorp requested that the effective date for the start of a transitional tariff be suspended while it works with stakeholders on a collaborative process to resolve net metering rate design issues. The filing also requests an increase in the application fees for net metering. In February 2017, the UPSC ruled on motions to dismiss and requests for a show cause order for a regulatory rate review filed by various parties to the docket and denied the motions. On August 28, 2017, PacifiCorp filed a settlement stipulation in the net metering proceeding. The stipulation provides for the closure of the net metering program to new entrants on November 15, 2017, with a transition to a new program that provides a separate compensation rate for exported power. All net metering customers, including those with a submitted application, as of November 15, 2017, will be grandfathered into the current program until January 1, 2036. A new proceeding will be initiated to establish a methodology for the determination of the export credit for new customers. During this period, a transition program for new customers will commence November 15, 2017, for a limited number of customers. Beginning December 1, 2017, PacifiCorp began accepting applications for the new transition program for private generation customers. Residential and non-residential private generation customers in the transition program will be compensated for exported energy at 90% and 92.5% of the current average energy rates, respectively. The rates for the exported energy will be fixed through January 1, 2033 for these transition program customers. The new residential and non-residential transition program customers' compensation will be only available for the first 170 MW and 70 MW, respectively. The stipulation also includes an agreement to support a two-year extension on the state tax credit for residential solar installations. A hearing on the stipulation was held on September 18, 2017, and an order approving it was issued September 29, 2017.

Oregon

In March 2017, PacifiCorp submitted its filing for the annual TAM filing in Oregon requesting an annual increase of $18 million, or an average price increase of 1.5%, based on forecasted net power costs and loads for calendar year 2018. Consistent with Oregon Senate Bill 1547, the filing includes an update of the impact of expiring production tax credits, which accounts for $6 million of the total rate adjustment. In October 2017, the OPUC issued an order approving PacifiCorp's request with some minor adjustments to the NPC modeling. PacifiCorp submitted the final update in November 2017 which reflected a rate increase of $2 million, or an average price increase of 0.2%, effective January 2018.

Wyoming

In April 2017, PacifiCorp filed its annual ECAM, REC and RRA applications with the WPSC. The ECAM filing requests approval to refund to customers $5 million in deferred net power costs for the period January 1, 2016 through December 31, 2016, and the RRA application requests approval to refund to customers $1 million. In June 2017, the WPSC approved the ECAM, REC and RRA rates on an interim basis. In November 2017, a stipulation was filed resolving all issues in the proceeding. The stipulation results in an additional refund to customers of $1 million in 2017. The WPSC approved the stipulation at the hearing on November 28, 2017.

Washington

In August 2017, PacifiCorp submitted a compliance filing to implement the second-year rate increase approved as part of the two-year rate plan in the 2015 regulatory rate review. The compliance filing included rates based on the $8 million, or 2.3%, increase ordered by the WUTC in September 2016. The compliance filing was approved by the WUTC on September 14, 2017, with rates effective September 15, 2017. On December 1, 2017, PacifiCorp submitted a tariff filing to implement the first price change for the decoupling mechanism approved in PacifiCorp's 2015 regulatory rate review. WUTC staff disputed PacifiCorp's interpretation of the WUTC's order for the decoupling mechanism and PacifiCorp's subsequent calculations requesting additional funds be booked for return to customers. In February 2018, the WUTC granted the staff's motions and rejected PacifiCorp's tariff revision and required that PacifiCorp re-file price changes for its decoupling mechanism.

Idaho

In January 2017, a $1 million, or 0.4%, decrease in base rates became effective as a result of a filing made with the IPUC to update net power costs in base rates in compliance with a prior rate plan stipulation.

In March 2017, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $8 million for deferred costs in 2016. This filing includes recovery of the difference in actual net power costs to the base level in rates, an adder for recovery of the Lake Side 2 resource, recovery of Deer Creek longwall mine investment and changes in production tax credits and renewable energy credits. The IPUC approved the ECAM application with rates effective June 1, 2017.

California

In April 2017, PacifiCorp filed an application with the CPUC for an overall rate increase of 1.3% to recover $3 million of costs recorded in the catastrophic events memorandum account over a two-year period effective April 1, 2018. The catastrophic events memorandum account includes costs for implementing drought-related fire hazard mitigation measures and storm damage and recovery efforts associated with the December 2016 and January 2017 winter storms. The CPUC issued an order in February 2018 approving this request.

In August 2017, PacifiCorp filed for a rate decrease of $1 million, or 1.1%, through its annual ECAC. The CPUC issued an order approving PacifiCorp's request in December 2017, the rate decrease was effective January 2018.

MidAmerican Energy

In July 2014, the IUB issued an order approving increases in MidAmerican Energy's Iowa retail electric base rates over approximately three years with equal annualized increases in revenues of $45 million, effective August 2013 and again on January 1, 2015 and 2016, for a total annualized increase of $135 million when fully implemented. In addition to an increase in base rates, the order approved, among other items, a revenue sharing mechanism that shares with MidAmerican Energy's customers 80% of revenues related to equity returns above 11% and 100% of revenues related to equity returns above 14%, with the customer portion of any sharing reducing rate base. MidAmerican Energy recorded a regulatory liability for revenue sharing totaling $26 million in 2017 and $30 million in 2016, which reduced rate base in the respective following January. In August 2016, the IUB issued an order approving ratemaking principles related to MidAmerican Energy's construction of up to 2,000 MW (nominal ratings) of additional wind-powered generating facilities. The ratemaking principles modified the revenue sharing mechanism, effective in 2018, such that sharing will be triggered each year by MidAmerican Energy's actual equity returns above a threshold calculated annually in accordance with the order. The threshold is the weighted average of equity returns for rate base as authorized via ratemaking principles proceedings and for remaining rate base, interest rates on 30-year single A-rated utility bond yields plus 400 basis points, with a minimum return of 9.5%. Pursuant to the change in revenue sharing, MidAmerican Energy will share with customers 100% of the revenue in excess of this trigger. Such revenue sharing will reduce coal and nuclear generation rate base, which is intended to mitigate future base rate increases.

The 2017 Tax Reform enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the U.S. federal corporate income tax rate from 35% to 21%. MidAmerican Energy has made filings or has been in discussions with each of its state rate regulatory bodies proposing either a reduction in retail rates or rate base for all or a portion of the net benefits of the 2017 Tax Reform for 2018 and beyond. MidAmerican Energy has proposed in Iowa, its largest jurisdiction, to reduce customer revenue via a rider mechanism for 50% of the lower annual income tax expense resulting from the decrease in federal tax rates, updated annually. Results for the Iowa electric jurisdiction will be subject to Iowa revenue sharing provisions. If MidAmerican Energy's filings in each of its rate jurisdictions are approved as proposed, it is estimated that 2018 revenue will be reduced by approximately $72 million, subject to change depending upon actual results of operations. MidAmerican Energy cannot predict the timing or ultimate outcome of regulatory actions on its proposals.

NV Energy (Nevada Power and Sierra Pacific)

Regulatory Rate Reviews

In June 2017, Nevada Power filed an electric regulatory rate review with the PUCN. The filing supported an annual revenue increase of $29 million, or 2%, but requested no incremental annual revenue relief. In December 2017, the PUCN issued an order which reduced Nevada Power's revenue requirement by $26 million and requires Nevada Power to share 50% of revenues related to equity returns above 9.7%. As a result of the order, Nevada Power recorded expense of $28 million primarily due to the reduction of a regulatory asset to return to customers revenue collected for costs not incurred. In January 2018, Nevada Power filed a petition for clarification of certain findings and directives in the order. The new rates were effective in February 2018.

The 2017 Tax Reform enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the U.S. federal corporate income tax rate from 35% to 21%. In February 2018, the Nevada Utilities made filings with the PUCN proposing a tax rate reduction rider for the lower annual income tax expense anticipated to result from the 2017 Tax Reform for 2018 and beyond. The filings support an annual rate reduction of $59 million and $25 million for Nevada Power and Sierra Pacific, respectively. The Nevada Utilities cannot predict the timing or ultimate outcome of regulatory actions on its proposals.

In June 2016, Sierra Pacific filed an electric regulatory rate review with the PUCN. The filing requested no incremental annual revenue relief. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving most, but not all, issues in the proceeding and reduced Sierra Pacific's electric revenue requirement by $3 million spread evenly to all rate classes. In December 2016, the PUCN approved the settlement agreement and established an additional six MW of net metering capacity under the grandfathered rates, which are those net metering rates that were in effect prior to January 2016; the order establishes cost-based rates and a value-based excess energy credit for customers who choose to install private generation after the six MW limitation is reached. The new rates were effective January 1, 2017. In January 2017, Sierra Pacific filed a petition for reconsideration relating to the creation of the additional six MW of net metering at the grandfathered rates. Sierra Pacific believes the effects of the PUCN decision results in additional cost shifting to non-net metering customers and reduces the stipulated rate reduction for other customer classes. In June 2017, the PUCN denied the petition for reconsideration.

In June 2016, Sierra Pacific filed a gas regulatory rate review with the PUCN. The filing requested a slight decrease in its incremental annual revenue requirement. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving all issues in the proceeding and reduced Sierra Pacific's gas revenue requirement by $2 million. In December 2016, the PUCN approved the settlement agreement. The new rates were effective January 1, 2017.

EEPR and EEIR

EEPR was established to allow the Nevada Utilities to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by the Nevada Utilities and approved by the PUCN in integrated resource plan proceedings. To the extent the Nevada Utilities' earned rate of return exceeds the rate of return used to set base general rates, the Nevada Utilities' are required to refund to customers EEIR revenue previously collected for that year. In March 2017, the Nevada Utilities each filed an application to reset the EEIR and EEPR and refund the EEIR revenue received in 2016, including carrying charges. In September 2017, the PUCN issued an order accepting a stipulation requiring Nevada Power to refund the 2016 revenue and reset the rates as filed effective October 1, 2017. The current EEIR liability for Nevada Power and Sierra Pacific is $10 million and $1 million, respectively, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2017.

Chapter 704B Applications

Chapter 704B of the Nevada Revised Statutes allows retail electric customers with an average annual load of one MW or more to file with the PUCN an application to purchase energy from alternative providers of a new electric resource and become distribution only service customers. On a case-by-case basis, the PUCN will assess the application and may deny or grant the application subject to conditions, including paying an impact fee, paying on-going charges and receiving approval for specific alternative energy providers and terms. The impact fee and on-going charges are assessed to alleviate the burden on other Nevada customers for the applicant's share of previously committed investments and long-term renewable contracts and are set at a level designed such that the remaining customers are not subjected to increased costs.

In May 2015, MGM Resorts International ("MGM") and Wynn Las Vegas, LLC ("Wynn"), filed applications with the PUCN to purchase energy from alternative providers of a new electric resource and become distribution only service customers of Nevada Power. In December 2015, the PUCN granted the applications subject to conditions, including paying an impact fee, on-going charges and receiving approval for specific alternative energy providers and terms. In December 2015, the applicants filed petitions for reconsideration. In January 2016, the PUCN granted reconsideration and updated some of the terms, including removing a limitation related to energy purchased indirectly from NV Energy. In September 2016, MGM and Wynn paid impact fees of $82 million and $15 million, respectively. In October 2016, MGM and Wynn became distribution only service customers and started procuring energy from another energy supplier. In April 2017, Wynn filed a motion with the PUCN seeking relief from the January 2016 order and requested the PUCN adopt an alternative impact fee and revise on-going charges associated with retirement of assets and high cost renewable contracts. This request is still pending. In May 2017, a stipulation reached between MGM, Regulatory Operations Staff and the Bureau of Consumer Protection was filed requiring Nevada Power to reduce the original $82 million impact fee by $16 million and apply the credit against MGM's remaining on-going charge obligation. In June 2017, the PUCN approved the stipulation as filed.

In September 2016, Switch, Ltd. ("Switch"), a customer of the Nevada Utilities, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Nevada Power and Sierra Pacific. In December 2016, the PUCN approved a stipulation agreement that allows Switch to purchase energy from alternative providers subject to conditions, including paying an impact fee to Nevada Power. In May 2017, Switch paid impact fees of $27 million and, in June 2017, Switch became a distribution only service customer and started procuring energy from another energy supplier.

In November 2016, Caesars Enterprise Service ("Caesars"), a customer of the Nevada Utilities, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Nevada Power and Sierra Pacific. In March 2017, the PUCN approved the application allowing Caesars to purchase energy from alternative providers subject to conditions, including paying an impact fee. In March 2017, Caesars provided notice that it intends to pay the impact fee monthly for three and six years at Sierra Pacific and Nevada Power, respectively, and proceed with purchasing energy from alternative providers. In July 2017, Caesars made the required compliance filings and, in September 2017, the PUCN issued an order allowing Caesars to acquire electric energy and ancillary services from another energy supplier and become a distribution only service customer of the Nevada Utilities. In December 2017, Caesars provided notice that it intends to transition eligible meters in the Nevada Power service territory to unbundled electric service in February 2018 at the earliest. In January 2018, Caesars became a distribution only service customer and started procuring energy from another energy supplier for its eligible meters in the Sierra Pacific service territory.

In May 2017, Peppermill Resort Spa Casino ("Peppermill"), a customer of Sierra Pacific, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Sierra Pacific. In August 2017, the PUCN approved a stipulation allowing Peppermill to purchase energy from alternative providers subject to conditions, including paying an impact fee. In September 2017, Peppermill provided notice that it intends to pay the impact fee and proceed with purchasing energy from alternative providers.

Net Metering

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

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

In January 2016, the PUCN denied requests to stay the order issued December 23, 2015. The PUCN also voted to reopen the evidentiary proceeding to address the application of new net metering rules for customers who applied for net metering service before the issuance of the final order. In February 2016, the PUCN affirmed most of the provisions of the December 23, 2015 order and adopted a twelve-year transition plan for changing rates for net metering customers to cost-based rates for utility services and value-based pricing for excess energy. Subsequently, two solar industry interest groups filed petitions for judicial review of the PUCN order issued in February 2016. The petitions request that the court either modify the PUCN order or direct the PUCN to modify its decision in a manner that would maintain rates and rules of service applicable to net metering as existed prior to the December 23, 2015 order of the PUCN. Two of the three petitions filed by the solar industry interest groups have been dismissed. In September 2016, the state district court issued an order in the third petition. The court concluded that the PUCN failed to provide existing net metering customers adequate legal notice of the proceeding. The court affirmed the PUCN's decision to establish new net energy metering rates and apply those to new net metering customers. The Nevada state district court decision was appealed to the Nevada Supreme Court, which was settled and dismissed in August 2017.

In July 2016, the Nevada Utilities filed applications with the PUCN to revert back to the original net metering rates for a period of twenty years for customers who installed or had an active application for private, renewable generating facilities as of December 31, 2015. In September 2016, the PUCN issued an order accepting the stipulation and approved the applications as modified by the stipulation. In December 2016, as a part of Sierra Pacific's regulatory rate review, the PUCN issued an order establishing an additional six MWs of net metering under the grandfathered rates in the Sierra Pacific service territory. As mentioned above, Sierra Pacific filed a petition for reconsideration relating to the additional six MWs of net metering, which was denied in June 2017.

Nevada enacted Assembly Bill 405 ("AB 405") on June 15, 2017. The legislation, among other things, established net metering crediting rates for private generation customers with installed net metering systems less than 25 kilowatts. Under AB 405, private generation customers will be compensated at 95% of the rate the customer would have paid for a kilowatt-hour of electricity supplied by the Nevada Utilities for the first 80 MWs of cumulative installed capacity of all net metering systems in Nevada, 88% of the rate the customer would have paid for a kilowatt-hour of electricity supplied by the Nevada Utilities for the next 80 MWs of cumulative installed capacity in Nevada, 81% of the rate the customer would have paid for a kilowatt-hour of electricity supplied by the Nevada Utilities for the next 80 MWs of cumulative installed capacity in Nevada and 75% of the rate the customer would have paid for a kilowatt-hour of electricity supplied by the Nevada Utilities for any additional private generation capacity. In July 2017, the Nevada Utilities filed with the PUCN proposed amendments to their tariffs necessary to comply with the provisions of AB 405. The filing in July 2017 also included a proposed optional time of use rate tariff for both Nevada Power and Sierra Pacific, which has not yet been set for procedural review. In September 2017, the PUCN issued an order directing the Nevada Utilities to place all new private generation customers who have submitted applications after June 15, 2017 into a new rate class with rates equal to the rate class they would be in if they were not private generation customers. Private generation customers with installed net metering systems less than 25-kilowatts prior to June 15, 2017 may elect to migrate to the new rate class created under AB 405 or stay in their otherwise-applicable rate class. The new AB 405 rates became effective December 1, 2017.

Emissions Reduction and Capacity Replacement Plan

Consistent with the Emissions Reduction and Capacity Replacement Plan ("ERCR Plan"), Nevada Power acquired a 272-MW natural gas co-generating facility in 2014, acquired a 210-MW natural gas peaking facility in 2014, constructed a 15-MW solar photovoltaic facility in 2015 and contracted two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities in 2015. In February 2016, Nevada Power solicited proposals to acquire 35 MW of nameplate renewable energy capacity to be owned by Nevada Power. Nevada Power did not enter into any agreements to acquire the 35 MW of nameplate renewable energy capacity; however, it has the option to acquire the 35 MW in the future under the ERCR Plan, subject to PUCN approval. In addition, Nevada Power was granted approval to purchase the remaining 130 MW of the Silverhawk natural gas-fueled combined cycle generating facility. In June 2016, Nevada Power executed a long-term power purchase agreement for 100 MW of nameplate renewable energy capacity in Nevada. In December 2016, the order was approved. In addition, the order approved the early retirement of Reid Gardner Unit 4 in the first quarter of 2017. These transactions are related to Nevada Power's compliance with Senate Bill No. 123, resulting in the retirement of 812 MW of coal-fueled generation by 2019.

IRP

In July 2016, Sierra Pacific filed its statutorily required IRP. In August 2016, Nevada Power filed an amendment to its related IRP. As a part of the filings, the Nevada Utilities sought PUCN authorization to acquire the South Point Energy Center, a 504-MW combined-cycle generating facility located in Arizona. In December 2016, the PUCN denied the acquisition of this facility. In January 2017, Nevada Power filed a petition for reconsideration relating to the acquisition of South Point Energy Center. In February 2017, the PUCN affirmed the denial of the acquisition of South Point Energy Center. The Nevada Utilities amended their respective IRPs in November 2017, requesting approval of three long-term renewable purchase power contracts. Nevada law was modified in 2017 under Senate Bill 146 and for future filings requires Nevada Power and Sierra Pacific to file jointly.

Kern River

In December 2016, Kern River filed a Stipulation and Agreement of Settlement with the FERC to establish an alternative set of rates for customers that extend service contracts associated with Kern River's original system and 2002 expansion, 2003 expansion and 2010 expansion projects. The stipulation provided a lower rate option to customers, improved the likelihood of re-contracting expiring capacity and extended recovery of Kern River's rate base. Under the stipulation, customers have the option to stay with previously established rates or choose the alternative lower rates. The reduction in rates was accomplished by extending the rate term to 25 years instead of the current term of 10 or 15 years, resulting in rates that are 9% to 26% lower than the previously established rates. Kern River received FERC approval of the stipulation in January 2017. The stipulation allowed regulatory depreciation on plant allocated to volumes of shippers that elected extended Period Two rates and plant allocated to capacity that has been turned back to be adjusted to 25 years, retroactive to the start of each Period Two term.

ALP

General Tariff Applications

In November 2014, ALP filed a general tariff application ("GTA") requesting 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. ALP amended the GTA in June 2015 and October 2015. In May 2016, the AUC issued its decision pertaining to the 2015-2016 GTA. ALP filed its 2015-2016 GTA compliance filing in July 2016 to comply with the AUC's decision and to provide customers with approximately C$415 million tariff relief in 2015 and 2016 through: (i) the discontinuance of construction work-in-progress ("CWIP") in rate base and the return to AFUDC accounting effective January 1, 2015, and (ii) the refund of previously collected CWIP in rate base as part of ALP's transmission tariffs during 2011-2014 less related returns. In October 2016, ALP amended its 2015-2016 GTA compliance filing made in July 2016 to reflect the impacts of the generic cost of capital decision issued in October 2016.

In December 2016, the AUC issued its decision with respect to ALP's 2015-2016 GTA compliance filing made in July 2016, as amended. The AUC found that ALP has either complied with or the AUC has otherwise relieved ALP from its compliance with all its directions in its decision except for Directive 47, which dealt with the determination of the refund for previously collected CWIP in rate base and all related amounts. In January 2017, ALP filed its second compliance filing as directed by the AUC and requested a technical conference to explain the technical aspects of the filing. In March 2017, the technical conference was held, and all key aspects of ALP's approach and methodologies used in its second compliance filing to comply with AUC directives were reviewed and discussed. In April 2017, ALP filed with the AUC an amendment to its second compliance filing.

In August 2017, the AUC issued a decision with respect to ALP's second compliance filing amendment filed in April 2017. The AUC denied ALP's proposal to remove C$7 million of recapitalized AFUDC associated with canceled projects on the basis that the amount would more appropriately be recovered through ALP's deferral account reconciliation process. The AUC also directed the recalculation of the amount of related income taxes using typical direct assigned project schedules filed in the general tariff applications, and to adjust its funded future income tax liability only for the change in timing differences.

In September 2017, ALP filed its third compliance filing with the AUC which proposed a one-time payment to the AESO of C$7 million to settle the 2015-2016 final transmission tariffs of C$485 million for 2016 and C$723 million for 2015. In December 2017, the AUC approved ALP's third compliance filing as filed.

ALP filed its 2017-2018 GTA in February 2016. The AUC held this application in abeyance pending the release of the 2015-2016 GTA Decision. ALP subsequently updated and refiled its 2017-2018 GTA in August 2016 to reflect the findings and conclusions of the AUC in its 2015-2016 GTA decision issued in May 2016. In October 2016, ALP amended its 2017-2018 GTA to reflect the impacts of the generic cost of capital decision issued in October 2016 and other updates and revisions. The amendment requests the AUC to approve ALP's revenue requirement of C$891 million for 2017 and C$919 million for 2018. The 2017-2018 GTA reflected an additional C$185 million of tariff relief related to items approved in the 2015-2016 GTA decision. In December 2016, the AUC approved ALP's request to enter into a negotiated settlement process.

In January 2017, ALP successfully reached a negotiated settlement with all parties regarding all aspects of ALP's 2017-2018 GTA and in February 2017, ALP filed with the AUC the 2017-2018 negotiated settlement application for approval. The application consists of negotiated reductions of C$16 million of operating expenses and C$40 million of transmission maintenance and information technology capital expenditures over the two years, as well as an increase to miscellaneous revenue of C$3 million. These reductions resulted in a C$24 million, or 1.3%, net decrease to the two-year total revenue requirement applied for in ALP's 2017-2018 GTA amendment filed in October 2016. In addition, ALP proposed to provide significant tariff relief through the refund of previously collected accumulated depreciation surplus of C$130 million (C$125 million net of other related impacts). The negotiated settlement agreement also provides for additional potential reductions over the two years through a 50/50 cost savings sharing mechanism.

During the second quarter 2017, ALP responded to information requests from the AUC with respect to its 2017-2018 negotiated settlement agreement application filed in February 2017. In August 2017, the AUC issued a decision approving ALP's negotiated settlement agreement for the 2017-2018 GTA, as filed. Also, the AUC approved a C$31 million refund of accumulated depreciation surplus as opposed to the C$130 million refund proposed by ALP and three customer groups.

In November 2017, ALP filed and received AUC approval regarding its compliance filing, which includes revenue requirements of C$864 million and C$888 million for 2017 and 2018, respectively.

2018 Generic Cost of Capital Proceeding

In July 2017, the AUC denied the utilities' request that the interim determinations of 8.5% return on equity and deemed capital structures for 2018 be made final, by stating that it is not prepared to finalize 2018 values in the absence of an evidentiary process and its intention to issue the generic cost of capital decision for 2018, 2019 and 2020 by the end of 2018 to reduce regulatory lag. The AUC also confirmed the process timelines with an oral hearing scheduled for March 2018.

In October 2017, ALP's evidence was submitted recommending a range of 9% to 10.75% return on equity, on a recommended equity ratio of 40%. ALP also filed evidence outlining increased uncertainties in the Alberta utility regulatory environment. In January 2018, the Consumers' Coalition of Alberta, the Utilities Consumer Advocate and the City of Calgary filed intervenor evidence. The return on equity recommended by the intervenors ranges from 6.3% to 7.75%. The equity ratio recommended by the intervenors for ALP ranges from 35% to 37%.

Deferral Account Reconciliation Application

In April 2017, ALP filed its application with the AUC with respect to ALP's 2014 projects and deferral accounts and specific 2015 projects. The application includes approximately C$2.0 billion in net capital additions. In June 2017, the AUC ruled that the scope of the deferral account proceeding would not be extended to consider the utilization of assets for which final cost approval is sought. However, the AUC will initiate a separate proceeding to address the issue of transmission asset utilization and how the corporate and property law principles applied in the Utility Asset Disposition decision may relate.

In December 2017, ALP amended its application to include the remaining capital projects completed in 2015. The amended 2014 and 2015 deferral account reconciliation application includes 110 completed projects with total gross capital additions, excluding AFUDC, of C$3.8 billion.

BHE U.S. Transmission

A significant portion of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base regulatory rate review. In December 2017, the most recent interim rate change filing was approved which set total annual revenue requirements at $332 million and a rate base of $2.5 billion. In January 2017, the PUCT approved ETT's request to suspend the base regulatory rate review filing scheduled for February 2017 and set ETT's annual revenue requirement to $327 million, effective March 2017. Results of a base regulatory rate review would be prospective except for any deemed disallowance by the PUCT of the transmission investment since the initial base regulatory rate review in 2007.

ENVIRONMENTAL LAWS AND REGULATIONS

Each Registrant is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact each Registrant's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state, local and international agencies. Each Registrant believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" of each respective Registrant in Item 7 of this Form 10-K for discussion of each Registrant's forecast environmental-related capital expenditures.

Clean Air Act Regulations

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

National Ambient Air Quality Standards

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

In October 2015, the EPA revised the national ambient air quality standard for ground level ozone, strengthening the standard from 75 parts per billion to 70 parts per billion. It is anticipated that the EPA will make attainment/nonattainment designations for the revised standards by late 2017. Nonattainment areas will have until 2020 to late 2037 to meet the standard. Given the level at which the standard was set in conjunction with retirements and the installation of controls, the new standard is not expected to have a significant impact on the relevant Registrant. The EPA designated the entire state of Iowa as attainment/unclassifiable on November 16, 2017.

Until the 2015 standard is fully implemented, the EPA continues to implement the 2008 ozone standards. The Upper Green River Basin Area in Wyoming, including all of Sublette and portions of Lincoln and Sweetwater Counties, were proposed to be designated as nonattainment for the 2008 ozone standard. When the final designations were released in April 2012, portions of Lincoln and Sweetwater Counties and Sublette County were determined to be in marginal nonattainment. While PacifiCorp's Jim Bridger plant is located in Sweetwater County, it is not in the portion of the designated nonattainment area and has not been impacted by the 2012 designation. In December 2017, EPA Region 9 notified Nevada of its intent to designate a portion of Clark County as nonattainment under the 2015 standard and will modify the state's recommendation for this area. The EPA also intends to designate all other areas in the state not previously designated as attainment/unclassifiable. This redesignation to nonattainment could potentially impact Nevada Power's Clark, Sun Peak, Las Vegas, Lenzie, Silverhawk, Harry Allen, Higgins, and Goodsprings generating facilities. However, until such time as the 2015 standard is implemented for Clark County in a final action, any potential impacts cannot be determined. In order for the EPA to consider more current air quality data in the final designation, Nevada must submit certified quality-assured air quality monitoring data for the time period 2015-2017 to the EPA by February 28, 2018. After considering any additional information received, the EPA plans to promulgate final ozone designations in spring of 2018.

On December 20, 2017, the EPA responded to the state of Arizona's recommendation that a section of Yuma County, in which the Yuma independent power project is located, be designated as nonattainment with respect to the 2015 National Ambient Air Quality Standards for ozone, indicating its acceptance of the state's designations for areas in attainment, and requesting additional data to finalize designations of nonattainment areas by February 28, 2018. The Yuma independent power project could be impacted by the requirements of the final rule. Until such time as the designations are final, any potential impacts cannot be determined.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 100 parts per billion. In February 2012, the EPA published final designations indicating that based on air quality monitoring data, all areas of the country are designated as "unclassifiable/attainment" for the 2010 nitrogen dioxide national ambient air quality standard.

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide. Under the 2010 rule, areas must meet a one-hour standard of 75 parts per billion utilizing a three-year average. The rule utilizes source modeling in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas. Attainment designations were due by June 2012; however, citing a lack of sufficient information to make the designations, the EPA did not issue its final designations until July 2013 and determined, at that date, that a portion of Muscatine County, Iowa was in nonattainment for the one-hour sulfur dioxide standard. MidAmerican Energy's Louisa coal-fueled generating facility is located just outside of Muscatine County, south of the violating monitor. In its final designation, the EPA indicated that it was not yet prepared to conclude that the emissions from the Louisa coal-fueled generating facility contribute to the monitored violation or to other possible violations, and that in a subsequent round of designations, the EPA will make decisions for areas and sources outside Muscatine County. MidAmerican Energy does not believe a subsequent nonattainment designation will have a material impact on the Louisa coal-fueled generating facility. Although the EPA's July 2013 designations did not impact PacifiCorp's nor the Nevada Utilities' generating facilities, the EPA's assessment of sulfur dioxide area designations will continue with the deployment of additional sulfur dioxide monitoring networks across the country.

The Sierra Club filed a lawsuit against the EPA in August 2013 with respect to the one-hour sulfur dioxide standards and its failure to make certain attainment designations in a timely manner. In March 2015, the United States District Court for the Northern District of California ("Northern District of California") accepted as an enforceable order an agreement between the EPA and Sierra Club to resolve litigation concerning the deadline for completing the designations. The Northern District of California's order directed the EPA to complete designations in three phases: the first phase by July 2, 2016; the second phase by December 31, 2017; and the final phase by December 31, 2020. The first phase of the designations require the EPA to designate two groups of areas: 1) areas that have newly monitored violations of the 2010 sulfur dioxide standard; and 2) areas that contain any stationary source that, according to the EPA's data, either emitted more than 16,000 tons of sulfur dioxide in 2012 or emitted more than 2,600 tons of sulfur dioxide and had an emission rate of at least 0.45 lbs/sulfur dioxide per million British thermal unit in 2012 and, as of March 2, 2015, had not been announced for retirement. MidAmerican Energy's George Neal Unit 4 and the Ottumwa Generating Station (in which MidAmerican Energy has a majority ownership interest, but does not operate), are included as units subject to the first phase of the designations, having emitted more than 2,600 tons of sulfur dioxide and having an emission rate of at least 0.45 lbs/sulfur dioxide per million British thermal unit in 2012. States may submit to the EPA updated recommendations and supporting information for the EPA to consider in making its determinations. Iowa submitted documentation to the EPA in April 2016 supporting its recommendation that Des Moines, Wapello and Woodbury Counties be designated as being in attainment of the standard. In July 2016, the EPA's final designations were published in the Federal Register indicating portions of Muscatine County, Iowa were in nonattainment with the 2010 sulfur dioxide standard, Woodbury County, Iowa was unclassifiable, and Des Moines and Wapello Counties were unclassifiable/attainment.

On January 9, 2018, the EPA published the results for the Air Quality Designations for the 2010 Sulfur Dioxide Primary National Ambient Air Quality Standard-Round 3 in the Federal Register. The Utah county of Emery, where PacifiCorp's Hunter and Huntington generation stations are located, was classified as attainment/unclassifiable. The Wyoming counties of Campbell and Lincoln, where PacifiCorp's Wyodak and Naughton generation stations are located, were classified as attainment/unclassifiable. The eastern portion of Sweetwater County, where PacifiCorp's Jim Bridger generation station is located, was classified as attainment/unclassifiable. Converse County, where PacifiCorp's Dave Johnston generation station is located, will not be designated until December 31, 2020.

In December 2012, the EPA finalized more stringent fine particulate matter national ambient air quality standards, reducing the annual standard from 15 micrograms per cubic meter to 12 micrograms per cubic meter and retaining the 24-hour standard at 35 micrograms per cubic meter. The EPA did not set a separate secondary visibility standard, choosing to rely on the existing secondary 24-hour standard to protect against visibility impairment. In December 2014, the EPA issued final area designations for the 2012 fine particulate matter standard. Based on these designations, the areas in which the relevant Registrant operates generating facilities have been classified as "unclassifiable/attainment." Unless additional monitoring suggests otherwise, the relevant Registrant does not anticipate that any impacts of the revised standard will be significant.

In December 2014, the Utah SIP for fine particulate matter was adopted by the Utah Air Quality Board. PacifiCorp's Lake Side and Gadsby generating facilities operate within nonattainment areas for fine particulate matter; however, the SIP did not impose significant new requirements on PacifiCorp's impacted generating facilities, nor did the EPA's comments on the Utah SIP identify requirements for PacifiCorp's existing generating facilities that would have a material impact on its consolidated financial results.

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

Mercury and Air Toxics Standards

In March 2011, the EPA proposed a rule that requires coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards. The final MATS became effective on April 16, 2012, and required that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015 with the potential for individual sources to obtain an extension of up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The relevant Registrants have completed emission reduction projects to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants.

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

Numerous lawsuits have been filed in the D.C. Circuit challenging the MATS. In April 2014, the D.C. Circuit upheld the MATS requirements. In November 2014, the United States Supreme Court agreed to hear the MATS appeal on the limited issue of whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. Oral argument in the case was held before the United States Supreme Court in March 2015, and a decision was issued by the United States Supreme Court in June 2015, which reversed and remanded the MATS rule to the D.C. Circuit for further action. The United States Supreme Court held that the EPA had acted unreasonably when it deemed cost irrelevant to the decision to regulate generating facilities, and that cost, including costs of compliance, must be considered before deciding whether regulation is necessary and appropriate. The United States Supreme Court's decision did not vacate or stay implementation of the MATS rule. In December 2015, the D.C. Circuit issued an order remanding the rule to the EPA, without vacating the rule. As a result, the relevant Registrants continue to have a legal obligation under the MATS rule and the respective permits issued by the states in which each respective Registrant operates to comply with the MATS rule, including operating all emissions controls or otherwise complying with the MATS requirements.

Cross-State Air Pollution Rule

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

The first phase of the rule was implemented January 1, 2015. In November 2015, the EPA released a proposed rule that would further reduce nitrogen oxides emissions in 2017. The final rule was published in the Federal Register in October 2016. The rule requires additional reductions in nitrogen oxides emissions beginning in May 2017. On December 23, 2016, a lawsuit was filed against the EPA in the D.C. Circuit over the final CSAPR "update" rule, which is still pending.

MidAmerican Energy has installed emissions controls at its coal-fueled generating facilities to comply with the CSAPR and may purchase emissions allowances to meet a portion of its compliance obligations. The cost of these allowances is subject to market conditions at the time of purchase and historically has not been material. MidAmerican Energy believes that the controls installed to date are consistent with the reductions to be achieved from implementation of the rule and does not anticipate that any impacts of the CSAPR update will be significant.

MidAmerican Energy operates natural gas-fueled generating facilities in Iowa and BHE Renewables operates natural gas-fueled generating facilities in Texas, Illinois and New York, which are subject to the CSAPR. However, the provisions are not anticipated to have a material impact on Berkshire Hathaway Energy or MidAmerican Energy. None of PacifiCorp's, Nevada Power's or Sierra Pacific's generating facilities are subject to the CSAPR. However, in a Notice of Data Availability published in the January 6, 2017, Federal Register, the EPA provided preliminary estimates of which upwind states may have linkages to downwind states experiencing ozone levels at or exceeding the 2015 ozone national ambient air quality standard of 70 parts per billion, and, using similar methodology to that in the CSAPR, indicated that Utah and Wyoming could have an obligation under the "good neighbor" provisions of the Clean Air Act to reduce nitrogen oxides emissions.

Regional Haze

The EPA's Regional Haze Rule, finalized in 1999, requires states to develop and implement plans to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's coal-fueled generating facilities in Utah, Wyoming, Arizona and Colorado and certain of Nevada Power's and Sierra Pacific's fossil-fueled generating facilities are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to best available retrofit technology ("BART") requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

The state of Utah issued a regional haze SIP requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Hunter Units 1 and 2, and Huntington Units 1 and 2. In December 2012, the EPA approved the sulfur dioxide portion of the Utah regional haze SIP and disapproved the nitrogen oxides and particulate matter portions. Certain groups appealed the EPA's approval of the sulfur dioxide portion and oral argument was heard before the United States Court of Appeals for the Tenth Circuit ("Tenth Circuit") in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. The state of Utah and PacifiCorp filed petitions for administrative and judicial review of the EPA's final rule on the BART determinations for the nitrogen oxides and particulate matter portions of Utah's regional haze SIP in March 2013. In May 2014, the Tenth Circuit dismissed the petition on jurisdictional grounds. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality completed an alternative BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2. The alternative BART analysis and revised regional haze SIP were submitted in June 2015 to the EPA for review and proposed action after a public comment period. In January 2016, the EPA published two alternative proposals to either approve the Utah SIP as written or reject the Utah SIP relating to nitrogen oxides controls and require the installation of selective catalytic reduction ("SCR") controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years. EPA's final action on the Utah regional haze SIP was effective August 4, 2016. The EPA approved in part and disapproved in part the Utah regional haze SIP and issued a federal implementation plan ("FIP") requiring the installation of SCR controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years of the effective date of the rule. PacifiCorp and other parties filed requests with the EPA to reconsider and stay that decision, as well as filed motions for stay and petitions for review with the Tenth Circuit asking the court to overturn the EPA's actions. In July 2017, the EPA issued a letter indicating it would reconsider its decision issuing the FIP. In light of the EPA's grant of reconsideration and the EPA's position in the litigation, the Tenth Circuit held the litigation in abeyance and imposed a stay of the compliance obligations of the FIP for the number of days the stay is in effect while the EPA conducts its reconsideration process.

The state of Wyoming issued two regional haze SIPs requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the sulfur dioxide SIP in December 2012 and the EPA's approval was upheld on appeal by the Tenth Circuit in October 2014. In addition, the EPA initially proposed in June 2012 to disapprove portions of the nitrogen oxides and particulate matter SIP and instead issue a FIP. The EPA withdrew its initial proposed actions on the nitrogen oxides and particulate matter SIP and the proposed FIP, published a re-proposed rule in June 2013, and finalized its determination in January 2014, which aligns more closely with the SIP proposed by the state of Wyoming. The EPA's final action on the Wyoming SIP approved the state's plan to have PacifiCorp install low-nitrogen oxides burners at Naughton Units 1 and 2, SCR controls at Naughton Unit 3 by December 2014, SCR controls at Jim Bridger Units 1 through 4 between 2015 and 2022, and low-nitrogen oxides burners at Dave Johnston Unit 4. The EPA disapproved a portion of 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 a portion of the Wyoming SIP and issued a FIP for the Wyodak coal-fueled generating facility ("Wyodak Facility"), requiring the installation of SCR controls within five years (i.e., by 2019). The EPA action became final on March 3, 2014. PacifiCorp filed an appeal of the EPA's final action on the Wyodak Facility in March 2014. The state of Wyoming also filed an appeal of the EPA's final action, as did the Powder River Basin Resource Council, National Parks Conservation Association and Sierra Club. In September 2014, the Tenth Circuit issued a stay of the March 2019 compliance deadline for the Wyodak Facility, pending further action by the Tenth Circuit in the appeal. A stay remains in place and the case has not yet been set for oral argument. In June 2014, the Wyoming Department of Environmental Quality issued a revised BART permit allowing Naughton Unit 3 to operate on coal through 2017 and providing for natural gas conversion of the unit in 2018; in October 2016, an application was filed with the Wyoming Department of Environmental Quality requesting a revision of the dates for the end of coal firing and the start of gas firing for Naughton Unit 3 to align with the requirements of the Wyoming SIP. The Wyoming Department of Environmental Quality approved a change to the requirements for Naughton Unit 3, extending the requirement to cease coal firing to no later than January 30, 2019, and complete the gas conversion by June 30, 2019. On March 17, 2017, Wyoming Department of Environmental Quality issued an extension to operate the unit as a coal-fueled unit through January 30, 2019. The Wyoming Department of Environmental Quality submitted a proposed revision to the Wyoming SIP, including a change to the Naughton Unit 3 compliance date, to the EPA for approval November 28, 2017.

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Cholla Unit 4. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP for the disapproved portions requiring SCR controls on Cholla Unit 4. PacifiCorp filed an appeal in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. The Ninth Circuit issued an order in February 2015, holding the matter in abeyance while the parties pursued an alternate compliance approach for Cholla Unit 4. The Arizona Department of Environmental Quality's revision of the draft permit and revision to the Arizona regional haze SIP were approved by the EPA through final action published in the Federal Register on March 27, 2017, with an effective date of April 26, 2017. The final action allows Cholla Unit 4 to utilize coal until April 30, 2025 and convert to gas or otherwise cease burning coal by June 30, 2025.

The state of Colorado regional haze SIP requires SCR controls at Craig Unit 2 and Hayden Units 1 and 2, in which PacifiCorp has ownership interests. Each of those regional haze compliance projects are either already in service or currently being constructed. In addition, in February 2015, the state of Colorado finalized an amendment to its regional haze SIP relating to Craig Unit 1, in which PacifiCorp has an ownership interest, to require the installation of SCR controls by 2021. In September 2016, the owners of Craig Units 1 and 2 reached an agreement with state and federal agencies and certain environmental groups that were parties to the previous settlement requiring SCR to retire Unit 1 by December 31, 2025, in lieu of SCR installation, or alternatively to remove the unit from coal-fueled service by August 31, 2021 with an option to convert the unit to natural gas by August 31, 2023, in lieu of SCR installation. The terms of the agreement were approved by the Colorado Air Quality Board in December 2016. The terms of the agreement were incorporated into an amended Colorado regional haze SIP in 2017 and were submitted to the EPA for its review and approval.

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

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. The EPA issued a final FIP on August 8, 2014 adopting, with limited changes, the Navajo Generating Station proposal as a "better than BART" determination. 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. In February 2017, the non-federal owners of the Navajo Generating Station announced the facility will shut down on or before December 23, 2019, unless new owners can be found. All current owners have since approved a lease extension with the Navajo Nation to allow operations to continue through 2019. As of the end of 2017, no viable offers for a new ownership structure were presented. In the event that a new owner is identified, compliance with the FIP, imposing a long-term facility-wide cap on total emissions of nitrogen oxides and alternative operating scenarios such as curtailment or other emission reductions equivalent to installation of selective catalytic reduction on two units in 2030, would be required.

Climate Change

In December 2015, an international agreement was negotiated by 195 nations to create a universal framework for coordinated action on climate change in what is referred to as the Paris Agreement. The Paris Agreement reaffirms the goal of limiting global temperature increase well below 2 degrees Celsius, while urging efforts to limit the increase to 1.5 degrees Celsius; establishes commitments by all parties to make nationally determined contributions and pursue domestic measures aimed at achieving the commitments; commits all countries to submit emissions inventories and report regularly on their emissions and progress made in implementing and achieving their nationally determined commitments; and commits all countries to submit new commitments every five years, with the expectation that the commitments will get more aggressive. In the context of the Paris Agreement, the United States agreed to reduce greenhouse gas emissions 26% to 28% by 2025 from 2005 levels. After more than 55 countries representing more than 55% of global greenhouse gas emissions submitted their ratification documents, the Paris Agreement became effective November 4, 2016. Under the terms of the Paris Agreement, ratifying countries are bound for a three-year period and must provide one-year's notice of their intent to withdraw. On June 1, 2017, President Trump announced the United States would withdraw from the Paris Agreement. Under the terms of the agreement, the withdrawal would be effective in November 2020. The cornerstone of the United States' commitment was the Clean Power Plan which was finalized by the EPA in 2015 but has since been proposed for repeal by the EPA.

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. On August 3, 2015, the EPA issued final new source performance standards, establishing a standard of 1,000 pounds of carbon dioxide per MWh for large natural gas-fueled generating facilities and 1,400 pounds of carbon dioxide per MWh for new coal-fueled generating facilities with the "Best System of Emission Reduction" reflecting highly efficient supercritical pulverized coal facilities with partial carbon capture and sequestration or integrated gasification combined-cycle units that are co-fired with natural gas or pre-combustion slipstream capture of carbon dioxide. The new source performance standards were appealed to the D.C. Circuit and oral argument was scheduled for April 17, 2017. However, oral argument was deferred and the court held the case in abeyance for an indefinite period of time. Until such time as the EPA undertakes further action to reconsider the new source performance standards or the court takes action, any new fossil-fueled generating facilities constructed by the relevant Registrants will be required to meet the GHG new source performance standards.

Clean Power Plan

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on the "Best System of Emission Reduction." In August 2015, the final Clean Power Plan was released, which established the Best System of Emission Reduction as including: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in-service after 2012. The compliance period would have begun in 2022, with three interim periods of compliance and with the final goal to be achieved by 2030 and was expected to reduce carbon dioxide emissions in the power sector to 32% below 2005 levels by 2030. On February 9, 2016, the United States Supreme Court ordered that the EPA's emission guidelines for existing sources be stayed pending the disposition of the challenges to the rule in the D.C. Circuit and any action on a writ of certiorari before the U.S. Supreme Court. Oral argument was heard before the D.C. Circuit on September 27, 2016. The court has not yet issued its decision. On October 10, 2017, the EPA issued a proposal to repeal the Clean Power Plan and the EPA will take comments on the proposed repeal until April 26, 2018. In addition, the EPA published in the Federal Register an Advance Notice of Proposed Rulemaking on December 28, 2017, seeking public input on, without committing to, a potential replacement rule. The public comment period for the Advance Notice of Proposed Rulemaking is currently scheduled to conclude February 26, 2018. The full impacts of the EPA's recent efforts to repeal the Clean Power Plan are not expected to have a material impact on the Registrants. 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 advanced customer energy efficiency programs.

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

- Pursue the construction of an additional 552 MW of new wind-powered generation in Iowa, increasing MidAmerican Energy's generating portfolio to more than 4,000 MW of wind, which was equivalent to an estimated 51 percent of its Iowa customers' annual retail usage in 2017. MidAmerican Energy surpassed its Climate Pledge commitments in 2016 and 2017 and is currently continuing with the construction of an additional 2,000 MW of wind-powered generation in Iowa, of which 334 MW was placed in-service in 2017. The 2,000-MW wind project is expected to be fully complete in late 2019, and by year-end 2020, MidAmerican Energy's annual renewable energy generation is expected to reach a level that is equivalent to more than 90% of its Iowa customers' annual retail usage. MidAmerican Energy owns the largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities.
- Retire more than 75 percent of the Nevada Utilities' coal-fueled generating capacity in Nevada by 2019. In accordance with the ERCR plan filed in May 2014, Nevada Power retired Reid Gardner Units Nos. 1-3 in December 2014 and Reid Gardner Unit No. 4 in March 2017, which represented 300 MW and 257 MW, respectively, of coal-fueled generating capacity in Nevada. Additionally, as part of the ERCR plan filed in May 2014 and approved by the PUCN, Nevada Power anticipates eliminating its ownership participation in the Navajo Generating Station in 2019.
- Add more than 1,000 MW of incremental solar and wind capacity through long-term power purchase agreements to PacifiCorp's owned 1,030 MW of wind-powered generating capacity. PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. PacifiCorp's Climate Pledge commitments were met December 2016. As of December 31, 2017, PacifiCorp's non-carbon generating capacity, owned and contracted, totaled 4,573 MW, which is capable of generating energy equivalent to 24 percent of its retail sales in 2017. In 2017, PacifiCorp announced Energy Vision 2020, which will significantly expand the amount of wind power serving customers by 2020 through a $3 billion investment in repowering its existing wind fleet with larger blades and newer technology; adding at least 1,311 megawatts of new wind resources by the end of 2020; and building transmission in Wyoming to enable additional wind generation.
- Invest in transmission infrastructure in the West and Midwest to support the integration of renewable energy onto the grid.
- Support and advance the development of markets in the West to optimize the electric grid, lower costs, enhance reliability and more effectively integrate renewable sources.

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

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing generating facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal-fueled generating facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and generating unit outputs may be lower;
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a greater business risk; and
- The relevant Registrant's natural gas pipeline operations, electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

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

Regional and State Activities

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

- In June 2013, Nevada SB 123 was signed into law. Among other things, SB 123 and regulations thereunder require Nevada Power to file with the PUCN an emission reduction and capacity replacement plan by May 1, 2014. In May 2014, Nevada Power filed its emissions reduction capacity replacement plan. The plan provided for the retirement or elimination of 300 MW of coal generating capacity by December 31, 2014, another 250 MW of coal generating capacity by December 31, 2017, and another 250 MW of coal generating capacity by December 31, 2019, along with replacement of such capacity with a mixture of constructed, acquired or contracted renewable and non-technology specific generating units. The plan also sets forth the expected timeline and costs associated with decommissioning coal-fired generating units that will be retired or eliminated pursuant to the plan. The PUCN has the authority to approve or modify the emission reduction and capacity replacement plan filed by Nevada Power. Given the PUCN may recommend and/or approve variations to Nevada Power's resource plans relative to requirements under SB 123, the specific impacts of SB 123 on Nevada Power cannot be determined.

- Under the authority of California's Global Warming Solutions Act, which includes a series of policies aimed at returning California greenhouse gas emissions to 1990 levels by 2020, 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. PacifiCorp is subject to the cap-and-trade program as a retail service provider in California and an importer of wholesale energy into California. In 2015, Governor Jerry Brown issued an executive order to reduce emissions to 40% below 1990 levels by 2030 and 80% by 2050. In September 2016, California Senate Bill 32 was signed into law establishing greenhouse gas emissions reduction targets of 40% below 1990 levels by 2030.

- The states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electricity generating resources. Under the laws in California and Oregon, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. Effective April 2013, Washington's amended emissions performance standards provide that GHG emissions for base load electricity generating resources must not exceed 970 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

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

- In September 2016, the Washington State Department of Ecology issued a final rule regulating GHG emissions from sources in Washington. The rule regulates greenhouse gases including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride beginning in 2017 with three-year compliance periods thereafter (i.e., 2017-2019, 2020-2022, etc.). Under the rule, the Washington State Department of Ecology established GHG emissions reduction pathways for all covered entities. Covered entities may use emission reduction units, which may be traded with other covered entities, to meet their compliance requirements. PacifiCorp's resources that are covered under the rule include the Chehalis generating facility, which is a natural gas combined-cycle plant located in Washington state. PacifiCorp received its baseline emission order on December 17, 2017, which specified the emission reduction requirements for the Chehalis generating facility every three years beginning in 2017. The reduction requirements average 1.7% per year. However, the Washington State Department of Ecology suspended the compliance obligations of the Clean Air Rule after a Thurston County Superior Court judge ruled the state lacks authority to mandate reductions from indirect emitters. Pending further interpretation of the court’s decision by the Washington State Department of Ecology, entities subject to the rule are required to continue reporting emissions.
- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to reduce GHG emissions in ten Northeastern and Mid-Atlantic states, required, beginning in 2009, the reduction of carbon dioxide emissions from the power sector of 10% by 2018. In May 2011, New Jersey withdrew from participation in the Regional Greenhouse Gas Initiative. Following a program review in 2012, the nine Regional Greenhouse Gas Initiative states implemented a new 2014 cap which was approximately 45% lower than the 2012-2013 cap. The cap is reduced each year by 2.5% from 2015 to 2020. As called for in the 2012 program review, a program review was initiated for 2016 and continues through 2017 with the expectation that states will implement program changes in the fourth control period from 2018 to 2020. In December 2017, an updated model rule was released by the Regional Greenhouse Gas Initiative states which includes an additional 30% regional cap reduction between 2020 and 2030.

GHG Litigation

Each Registrant closely monitors ongoing environmental litigation applicable to its respective operations. Numerous lawsuits have been unsuccessfully pursued against the industry that attempt to link GHG emissions to public or private harm. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. These cases have typically been appealed to federal appellate courts and, in certain circumstances, to the United States Supreme Court. In the U.S. Supreme Court's 2011 decision in the case of American Electric Power Co., Inc., et al. v. Connecticut et al., the court addressed the question of whether federal common law nuisance claims could be maintained against certain electric power companies' for their GHG emissions and require the setting of an emissions cap for the emitters. The court held that the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon dioxide emissions from fossil-fuel-fired power plants. Recent efforts by the EPA to repeal the Clean Power Plan could increase the filing of common law nuisance lawsuits against emitters of GHG. Adverse rulings in GHG-related cases could result in increased or changed regulations and could increase costs for GHG emitters, including the Registrants' generating facilities.

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

Renewable Portfolio Standards

Each state's RPS described below could significantly impact the relevant Registrant's consolidated financial results. Resources that meet the qualifying electricity requirements under each RPS vary from state to state. Each state's RPS requires some form of compliance reporting and the relevant Registrant can be subject to penalties in the event of noncompliance. Each Registrant believes it is in material compliance with all applicable RPS laws and regulations.

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.

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

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, and 20% in 2020 through 2024. In March 2016, Oregon Senate Bill No. 1547-B, the Clean Electricity and Coal Transition Plan, was signed into law. Senate Bill No. 1547-B requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030, and increases the current RPS target from 25% in 2025 to 50% by 2040. Senate Bill No. 1547-B also implements new REC banking provisions, as well as the following interim RPS targets: 27% in 2025 through 2029, 35% in 2030 through 2034, 45% in 2035 through 2039, and 50% by 2040 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.

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 California RPS required all California retail sellers to procure an average of 20% of retail load from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020. In October 2015, California Senate Bill No. 350 was signed into law, which increased the current RPS requirement to 40% by December 31, 2024, 45% by December 31, 2027 and 50% by December 31, 2030. In December 2011, the CPUC adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three product content categories of RPS-eligible resources established by the legislation that have been imposed on other California retail sellers.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. After significant litigation, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule was released in May 2014, and became effective in October 2014. Under the final rule, existing facilities that withdraw at least 25% of their water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day are required to reduce fish impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) by choosing one of seven options. Facilities that withdraw at least 125 million gallons of water per day from waters of the United States must also conduct studies to help their permitting authority determine what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms (i.e., when organisms are drawn into the facility). PacifiCorp and MidAmerican Energy are assessing the options for compliance at their generating facilities impacted by the final rule and will complete impingement and entrainment studies. PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw more than 125 million gallons per day of water from waters of the United States for once-through cooling applications. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter and Huntington generating facilities currently utilize closed cycle cooling towers but are designed to withdraw more than two million gallons of water per day. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The costs of compliance with the cooling water intake structure rule cannot be fully determined until the prescribed studies are conducted and the respective state environmental agencies review the studies to determine whether additional mitigation technologies should be applied. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant to the consolidated financial statements. Nevada Power and Sierra Pacific do not utilize once-through cooling water intake or discharge structures at any of their generating facilities. All of the Nevada Power and Sierra Pacific generating stations are designed to have either minimal or zero discharge; therefore, they are not impacted by the §316(b) final rule.

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally-promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's discharge permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018 and fully implemented by December 31, 2023. On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with the EPA. The EPA granted the request for reconsideration on April 12, 2017, imposed an immediate administrative stay of compliance dates in the rule that had not passed judicial review and requested the court stay the pending litigation over the rule until September 12, 2017. On June 6, 2017, the EPA proposed to extend many of the compliance deadlines that would otherwise occur in 2018 and on September 18, 2017, the EPA issued a final rule extending certain compliance dates for flue gas desulfurization wastewater and bottom ash transport water limits until November 1, 2020. While most of the issues raised by this rule are already being addressed through the coal combustion residuals rule and are not expected to impose significant additional requirements on the facilities, the impact of the rule cannot be fully determined until the reconsideration action is complete and any judicial review is conducted.

In April 2014, the EPA and the United States Army Corps of Engineers issued a joint proposal to address "waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of United States Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. The final rule was released in May 2015 but is currently under appeal in multiple courts and a nationwide stay on the implementation of the rule was issued in October 2015. On January 13, 2017, the U.S. Supreme Court granted a petition to address jurisdictional challenges to the rule. The EPA plans to undertake a two-step process, with the first step to repeal the 2015 rule and the second step to carry out a notice-and-comment rulemaking in which a substantive re-evaluation of the definition of the "waters of the United States" will be undertaken. On July 27, 2017, the EPA and the Corps of Engineers issued a proposal to repeal the final rule and recodify the pre-existing rules pending issuance of a new rule and on November 16, 2017, the agencies proposed to extend the implementation day of the "waters of the United States" rule to 2020; neither of the proposals has been finalized. On January 22, 2018, the U.S. Supreme Court issued its decision related to the jurisdictional challenges to the rule, holding that federal district courts, rather than federal appeals courts, have proper jurisdiction to hear challenges to the rule and instructed the Sixth Circuit Court of Appeals to dismiss the petitions for review for lack of jurisdiction, clearing the way for imposition of the rule in certain states barring final action by the EPA to formalize the extension of the compliance deadline. Depending on the outcome of final action by the EPA and additional legal action, a variety of projects that otherwise would have qualified for streamlined permitting processes under nationwide or regional general permits will be required to undergo more lengthy and costly individual permit procedures based on an extension of waters that will be deemed jurisdictional. However, until the rule is fully litigated and finalized, the Registrants cannot determine whether projects that include construction and demolition will face more complex permitting issues, higher costs or increased requirements for compensatory mitigation.

Coal Combustion Byproduct Disposal

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts under the RCRA. The final rule was released by the EPA on December 19, 2014, was published in the Federal Register on April 17, 2015 and was effective on October 19, 2015. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements. The final rule requires regulated entities to post annual groundwater monitoring and corrective action reports. The first of these reports will be posted to the respective Registrant's coal combustion rule compliance data and information websites by March 2, 2018. Based on the results in those reports, additional action may be required under the rule.

At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained coal combustion byproducts. Prior to the effective date of the rule in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive coal combustion byproducts and hence are not subject to the final rule. As PacifiCorp proceeded to implement the final coal combustion rule, it was determined that two surface impoundments located at the Dave Johnston Generating Station were hydraulically connected and effectively constitute a single impoundment. In November 2017, a new surface impoundment was placed into service at the Naughton Generating Station. At the time the rule was published in April 2015, MidAmerican Energy owned or operated nine surface impoundments and four landfills that contain coal combustion byproducts. Prior to the effective date of the rule in October 2015, MidAmerican Energy closed or repurposed six surface impoundments to no longer receive coal combustion byproducts. Five of these surface impoundments were closed on or before December 21, 2017 and the sixth is undergoing closure. At the time the rule was published in April 2015, the Nevada Utilities operated ten evaporative surface impoundments and two landfills that contained coal combustion byproducts. Prior to the effective date of the rule in October 2015, the Nevada Utilities closed four of the surface impoundments, four impoundments discontinued receipt of coal combustion byproducts making them inactive and two surface impoundments remain active and subject to the final rule. The two landfills remain active and subject to the final rule. Refer to Note 13 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 10 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for discussion of the impacts on asset retirement obligations as a result of the final rule.

Multiple parties filed challenges over various aspects of the final rule in the D.C. Circuit in 2015, resulting in settlement of some of the issues and subsequent regulatory action by the EPA, including subjecting inactive surface impoundments to regulation. On September 13, 2017, EPA Administrator Pruitt issued a letter to parties petitioning for administrative reconsideration of certain aspects of the coal combustion byproducts rule concluding it was appropriate and in the public interest to reconsider the provisions of the final rule addressed in the petitions. On September 27, 2017, the D.C. Circuit issued an order to the EPA requiring the agency to identify provisions of the rule that the agency intended to reconsider. The EPA submitted its list of potential issues to be reconsidered on November 15, 2017 and oral argument was held by the D.C. Circuit November 20, 2017 over certain portions of the final rule. The court has not yet issued a decision on the issues presented in the oral arguments. Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' coal combustion residuals permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. Utilizing that guidance, the state of Oklahoma submitted an application to the EPA for approval of its state program and, on January 16, 2018, the EPA proposed to approve the application. To date, none of the states in which the Registrants operate has submitted an application for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required two landfills to submit permit applications by March 2017. It is anticipated that the state of Utah will submit an application for approval of its coal combustion residuals permit program prior to the end of 2018.

Notwithstanding the status of the final coal combustion residuals rule, citizens' suits have been filed against regulated entities seeking judicial relief for contamination alleged to have been caused by releases of coal combustion byproducts. Some of these cases have been successful in imposing liability upon companies if coal combustion byproducts contaminate groundwater that is ultimately released or connected to surface water. In addition, actions have been filed against regulated entities seeking to require that surface impoundments containing coal combustion residuals be subject to closure by removal rather than being allowed to effectuate closure in place as provided under the final rule. The Registrants are not a party to these lawsuits and until they are resolved, the Registrants cannot predict the impact on overall compliance obligations.

Other

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

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.
- The Nuclear Waste Policy Act of 1982, under which the United States Department of Energy is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Refer to Note 13 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 12 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's nuclear decommissioning obligations.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of PacifiCorp's mining activities.
- The FERC evaluates hydroelectric systems to ensure environmental impacts are minimized, including the issuance of environmental impact statements for licensed projects both initially and upon relicensing. The FERC monitors the hydroelectric facilities for compliance with the license terms and conditions, which include environmental provisions. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for information regarding the relicensing of PacifiCorp's Klamath River hydroelectric system.

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

Item 1A. Risk Factors

Each Registrant is subject to numerous risks and uncertainties, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by the relevant Registrant, should be made before making an investment decision. Additional risks and uncertainties not presently known or which each Registrant currently deems immaterial may also impair its business operations. Unless stated otherwise, the risks described below generally relate to each Registrant.

Corporate and Financial Structure Risks

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

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

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

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

A significant portion of BHE's capital structure is comprised of debt, and BHE expects to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. As of December 31, 2017, BHE had the following outstanding obligations:

- senior unsecured debt of $6.5 billion;
- junior subordinated debentures of $100 million;
- short-term borrowings of $3.3 billion;
- guarantees and letters of credit in respect of subsidiary and equity method investments aggregating $332 million; and
- commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $265 million.

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $29.8 billion as of December 31, 2017. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) BHE's share of the outstanding debt of its own or its subsidiaries' equity method investments.

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

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

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

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

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

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

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

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

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

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

Business Risks

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

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

Any acquisition entails numerous risks, including, among others:

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

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

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

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

The operation of complex utility systems or interstate natural gas pipeline and storage systems that are spread over large geographic areas involves many operating uncertainties and events beyond each respective Registrant's control. These potential events include the breakdown or failure of the Registrants' thermal, nuclear, hydroelectric, solar, wind and other electricity generating facilities and related equipment, compressors, pipelines, transmission and distribution lines or other equipment or processes, which could lead to catastrophic events; unscheduled outages; strikes, lockouts or other labor-related actions; shortages of qualified labor; transmission and distribution system constraints; failure to obtain, renew or maintain rights-of-way, easements and leases on United States federal, Native American, First Nations or tribal lands; terrorist activities or military or other actions, including cyber attacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; third party excavation errors; unexpected degradation of pipeline systems; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, earthquakes, explosions, landslides, an electromagnetic pulse, mining incidents, litigation, wars, terrorism and embargoes. A catastrophic event might result in injury or loss of life, extensive property damage or environmental or natural resource damages. For example, in the event of an uncontrolled release of water at one of PacifiCorp's high hazard potential hydroelectric dams, it is probable that loss of human life, disruption of lifeline facilities and property damage could occur in the downstream population and civil or other penalties could be imposed by the FERC. Any of these events or other operational events could significantly reduce or eliminate the relevant Registrant's revenue or significantly increase its expenses, thereby reducing the availability of distributions to BHE. For example, if the relevant Registrant cannot operate its electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources. Further, the Registrants self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. The scope, cost and availability of each Registrant's insurance coverage may change, including the portion that is self-insured. Any reduction of each Registrant's revenue or increase in its expenses resulting from the risks described above, could adversely affect the relevant Registrant's consolidated financial results.

Each Registrant is subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability and other laws and regulations that affect its operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations, including initiatives regarding deregulation and restructuring of the utility industry, are continually being proposed and enacted that impose new or revised requirements or standards on each Registrant.

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

Compliance with applicable laws and regulations generally requires each Registrant to obtain and comply with a wide variety of licenses, permits, inspections, audits and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs and damages arising out of contaminated properties. Compliance activities pursuant to existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, each Registrant could be required to shut down some facilities or materially alter its operations. Further, each Registrant may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for its operating assets or development projects. Delays in, or active opposition by third parties to, obtaining any required environmental or regulatory authorizations or failure to comply with the terms and conditions of the authorizations may increase costs or prevent or delay each Registrant from operating its facilities, developing or favorably locating new facilities or expanding existing facilities. If any Registrant fails to comply with any environmental or other regulatory requirements, such Registrant may be subject to penalties and fines or other sanctions, including changes to the way its electricity generating facilities are operated that may adversely impact generation or how the Pipeline Companies are permitted to operate their systems that may adversely impact throughput. The costs of complying with laws and regulations could adversely affect each Registrant's consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require such Registrant to increase its purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect such Registrant's consolidated financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition and decreased revenues within each Registrant's service territories, such as the Nevada Energy Choice Initiative; new environmental requirements, including the implementation of or changes to the Clean Power Plan, RPS and GHG emissions reduction goals; the issuance of new or stricter air quality standards; the implementation of energy efficiency mandates; the issuance of regulations governing the management and disposal of coal combustion byproducts; changes in forecasting requirements; changes to each Registrant's service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where it lacks the exclusive right to serve its customers; the inability of each Registrant to recover its costs on a timely basis, if at all; new pipeline safety requirements; or a negative impact on each Registrant's current transportation and cost recovery arrangements. In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted from time to time that impose additional or new requirements or standards on each Registrant.

Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. The Registrants cannot accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions nor can each Registrant determine their impact on it at this time; however, any one of these could adversely affect each Registrant's consolidated financial results through higher capital expenditures and operating costs and early closure of generating facilities or restrict or otherwise cause an adverse change in how each Registrant operates its business. To the extent that each Registrant is not allowed by its regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the costs of complying with such additional requirements could have a material adverse effect on the relevant Registrant's consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on the relevant Registrant's consolidated financial results. The Registrants have made their best estimate regarding the impact of the 2017 Tax Reform and the probability and timing of settlements of net regulatory liabilities established pursuant to the 2017 Tax Reform. However, the amount and timing of the settlements may change based on decisions and actions by each Registrant's regulators, which could have an effect on the relevant Registrant's consolidated financial results.

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

State Regulatory Rate Review 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 or other jurisdiction. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs recovered through rates and from time-to-time may result in a state regulator requiring refunds to customers. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense, investment and capital structure that it deems are just and reasonable in providing the service and may disallow recovery in rates for any costs that it believes do not meet such standard. Additionally, each state regulatory commission establishes the allowed rate of return the Utilities will be given an opportunity to earn on their sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that each Registrant will be able to realize the allowed rate of return.

Energy cost increases above the level assumed in establishing base rates may be subject to customer sharing. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on the Utilities, despite efforts to minimize this impact through the use of hedging contracts and sharing mechanisms or through future general regulatory rate reviews. Any of these consequences could adversely affect each Registrant's consolidated financial results.

FERC Jurisdiction

The FERC authorizes cost-based rates associated with transmission services provided by the Utilities' transmission facilities. Under the Federal Power Act, the Utilities, or MISO as it relates to MidAmerican Energy, may voluntarily file, or may be obligated to file, for changes, including general rate changes, to their system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which the Utilities sell electricity at wholesale, has jurisdiction over most of PacifiCorp's hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict the ability of the Utilities to sell electricity at market-based rates, which could adversely affect each Registrant's consolidated financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. As a transmission owning member of MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. As participants in EIM, PacifiCorp, Nevada Power and Sierra Pacific are also subject to applicable California ISO rules, which are subject to FERC approval and operational procedures. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

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

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

Rates for the interstate natural gas transmission and storage operations at the Pipeline Companies, which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for charges, are authorized by the FERC. In accordance with the FERC's rate-making principles, the Pipeline Companies' current maximum tariff rates are designed to recover prudently incurred costs included in their pipeline system's regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline system and to afford the Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes the Pipeline Companies to charge their customers may not be sufficient to recover the costs incurred to provide services in any given period. Moreover, from time to time, the FERC may change, alter or refine its policies or methodologies for establishing pipeline rates and terms and conditions of service. In addition, the FERC has the authority under Section 5 of the Natural Gas Act of 1938 ("NGA") to investigate whether a pipeline may be earning more than its allowed rate of return and, when appropriate, to institute proceedings against such pipeline to prospectively 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. Under certain circumstances, FERC policy allows interstate natural gas pipelines to design new maximum tariff rates to recover such costs in regulatory rate reviews. 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 a significant portion of the DNO's actual costs. A resetting of the formula does not require the consent of the DNO, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law, or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of any price control, additional costs have a direct impact on the financial results of the Northern Powergrid Distribution Companies.

AUC Jurisdiction

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

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

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

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

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

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

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

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

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

Each Registrant actively pursues, develops and constructs new or expanded facilities. Each Registrant expects to incur significant annual capital expenditures over the next several years. Such expenditures may include construction and other costs for new electricity generating facilities, electric transmission or distribution projects, environmental control and compliance systems, natural gas storage facilities, new or expanded pipeline systems, and continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor, siting and permitting and changes in environmental and operational compliance matters, load forecasts and other items over a multi-year construction period, as well as counterparty risk and the economic viability of the Registrants' suppliers, customers and contractors. Certain of the Registrants' construction projects are substantially dependent upon a single supplier or contractor and replacement of such supplier or contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in-service and, in extreme cases, the loss of the power purchase agreements or other long-term off-take contracts underlying such projects. Such costs may not be recoverable in the regulated rates or market or contract prices each Registrant is able to charge its customers. Delays in construction of renewable projects may result in delayed in-service dates which may result in the loss of anticipated revenue or income tax benefits. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or recover any such costs could adversely affect such Registrant's consolidated financial results.

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

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

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

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity or natural gas;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- shifts in competitively priced natural gas supply sources away from the sources connected to the Pipeline Companies' systems, including shale gas sources;
- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by each Registrant through various existing laws and regulations, as well as, deregulation, conservation, energy efficiency and private generation measures and programs;
- laws mandating or encouraging renewable energy sources, which may decrease the demand for electricity and natural gas or change the market prices of these commodities;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels;
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise;
- a reduction in the state or federal subsidies or tax incentives that are provided to agricultural, industrial or other customers, or a significant sustained change in prices for commodities such as ethanol or corn for ethanol manufacturers; and
- sustained mild weather that reduces heating or cooling needs.

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

In most parts of the United States and other markets in which each Registrant operates, demand for electricity peaks during the summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, demand for electricity peaks during the winter when heating needs are higher. In addition, demand for natural gas and other fuels generally peaks during the winter. This is especially true in MidAmerican Energy's and Sierra Pacific's retail natural gas businesses. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may negatively impact electricity generation at PacifiCorp's hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, PacifiCorp and MidAmerican Energy have added substantial wind-powered generating capacity, and BHE's unregulated subsidiaries are adding solar and wind-powered generating capacity, each of which is also a climate-dependent resource.

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

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

In general, each Registrant's primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, demand for electricity, economic growth and changes in technology. Volumetric changes are caused by fluctuations in generation or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, the Utilities purchase electricity and fuel in the open market as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, the Utilities may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when the Utilities are a net seller of electricity in the wholesale market, the Utilities could earn less revenue. Although the Utilities have energy cost adjustment mechanisms, the risks associated with changes in market prices may not be fully mitigated due to customer sharing bands as it relates to PacifiCorp and other factors.

Potential terrorist activities and the impact of military or other actions, could adversely affect each Registrant's consolidated financial results.

The ongoing threat of terrorism and the impact of military or other actions by nations or politically, ethnically or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject each Registrant's operations to increased risks. Additionally, the United States government has issued warnings that energy assets, specifically pipeline, nuclear generation, transmission and other electric utility infrastructure, are potential targets for terrorist attacks. Political, economic, social or financial market instability or damage to or interference with the operating assets of the Registrants, customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair or other costs, any of which may materially adversely affect each Registrant in ways that cannot be predicted at this time. Any of these risks could materially affect its consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect each Registrant's ability to raise capital.

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

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

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

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

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

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

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

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

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

Each Registrant is subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. Each Registrant relies on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require the Utilities to incur additional expenses to meet customer needs. In addition, when these contracts terminate, the Utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

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

The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC and British Gas Trading Limited accounting for approximately 21% and 15%, respectively, of distribution revenue in 2017. AltaLink's primary source of operating revenue is the AESO. Generally, a single customer purchases the energy from BHE's independent power projects in the United States and the Philippines pursuant to long-term power purchase agreements. Any material performance failure by the counterparties in these arrangements could have a significant adverse impact on BHE's consolidated financial results.

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

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

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

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

Costs of providing each Registrant's defined benefit pension and other postretirement benefit plans and costs associated with the joint trustee plan to which PacifiCorp contributes depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, mortality assumptions, the interest rates used to measure required minimum funding levels, the funded status of the plans, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and each Registrant's required or voluntary contributions made to the plans. Certain of the Registrant's pension and other postretirement benefit plans are in underfunded positions. Even if sustained growth in the investments over future periods increases the value of these plans' assets, each Registrant will likely be required to make cash contributions to fund these plans in the future. Additionally, each Registrant's plans have investments in domestic and foreign equity and debt securities and other investments that are subject to loss. Losses from investments could add to the volatility, size and timing of future contributions.

Furthermore, the funded status of the UMWA 1974 Pension Plan multiemployer plan to which PacifiCorp's subsidiary previously contributed is considered critical and declining. PacifiCorp's subsidiary involuntarily withdrew from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp has recorded its best estimate of the withdrawal obligation. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that withdrew during the three years prior to a mass withdrawal.

In addition, MidAmerican Energy is required to fund over time the projected costs of decommissioning Quad Cities Station, a nuclear power plant, and Bridger Coal Company, a joint venture of PacifiCorp's subsidiary, Pacific Minerals, Inc., is required to fund projected mine reclamation costs. Funds that MidAmerican Energy has invested in a nuclear decommissioning trust and PacifiCorp has invested in a mine reclamation trust are invested in debt and equity securities and poor performance of these investments will reduce the amount of funds available for their intended purpose, which could require MidAmerican Energy or PacifiCorp to make additional cash contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on MidAmerican Energy's or PacifiCorp's liquidity by reducing their available cash.

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

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

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

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

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

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

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant. Significant dislocations and liquidity disruptions in the United States, Great Britain, Canada and global credit markets, such as those that occurred in 2008 and 2009, may materially impact liquidity in the bank and debt capital markets, making financing terms less attractive for borrowers that are able to find financing and, in other cases, may cause certain types of debt financing, or any financing, to be unavailable. Additionally, economic uncertainty in the United States or globally may adversely affect the United States' credit markets and could negatively impact each Registrant's ability to access funds on favorable terms or at all. If each Registrant is unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of its capital expenditures, acquisition financing and its consolidated financial results.

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

The Financial Accounting Standards Board ("FASB") and the SEC continuously make changes to accounting standards and disclosure and other financial reporting requirements. New or revised accounting standards and requirements issued by the FASB or the SEC or new accounting orders issued by the FERC could significantly impact each Registrant's consolidated financial results and disclosures. For example, beginning in 2018 all changes in the fair values of equity securities (whether realized or unrealized) will be recognized as gains or losses in the relevant Registrant's consolidated financial statements. Accordingly, periodic changes in such Registrant's reported net income will likely be subject to significant variability.

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

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

The following table summarizes Berkshire Hathaway Energy's electric generating facilities that are in operation as of December 31, 2017:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MW)	Net Owned Capacity (MW)
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Oregon, Texas, New York and Arizona	10,919	10,640
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Wyoming, Iowa, Utah, Arizona, Nevada, Colorado and Montana	16,232	9,158
Wind	PacifiCorp, MidAmerican Energy and BHE Renewables	Iowa, Wyoming, Nebraska, Washington, California, Texas, Oregon, Illinois and Kansas	6,533	6,524
Solar	BHE Renewables and NV Energy	California, Texas, Arizona, Minnesota and Nevada	1,675	1,527
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, The Philippines, Idaho, California, Utah, Hawaii, Montana, Illinois and Wyoming	1,299	1,277
Nuclear	MidAmerican Energy	Illinois	1,820	455
Geothermal	PacifiCorp and BHE Renewables	California and Utah	370	370
		Total	38,848	29,951

Additionally, the Company has electric generating facilities that are under construction in Iowa, Illinois and Minnesota as of December 31, 2017 having total Facility Net Capacity and Net Owned Capacity of 1,902 MW.

The right to construct and operate each Registrant's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through prescription, 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 ALP 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, Native American or 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 (including prescriptive easements), rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the electric transmission and distribution facilities and interstate natural gas pipelines. Each Registrant believes it has satisfactory title or interest to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

Each Registrant is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Each Registrant does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. Each Registrant is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts.

Item 4. Mine Safety Disclosures

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

PART II

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

BERKSHIRE HATHAWAY ENERGY

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

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

PACIFICORP

All common stock of PacifiCorp is held by its parent company, PPW Holdings LLC, which is a direct, wholly owned subsidiary of BHE. PacifiCorp declared and paid dividends to PPW Holdings LLC of $600 million in 2017 and $875 million in 2016.

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

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

All common stock of MidAmerican Energy is held by its parent company, MHC, which is a direct, wholly owned subsidiary of MidAmerican Funding. MidAmerican Funding is an Iowa limited liability company whose membership interest is held solely by BHE. Neither MidAmerican Funding or MidAmerican Energy declared or paid any cash distributions or dividends to its sole member or shareholder in 2017 and 2016.

For a discussion of regulatory restrictions that limit MidAmerican Energy's ability to pay dividends on common stock, refer to "Debt Authorizations and Related Matters" in MidAmerican Energy's Item 7 in this Form 10-K and to Note 9 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K.

NEVADA POWER

All common stock of Nevada Power is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Nevada Power declared and paid dividends to NV Energy of $548 million in 2017 and $469 million in 2016.

SIERRA PACIFIC

All common stock of Sierra Pacific is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Sierra Pacific declared and paid dividends to NV Energy of $45 million in 2017 and $51 million in 2016.

Item 8. Financial Statements and Supplementary Data

Berkshire Hathaway Energy Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

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

Results of Operations

Overview

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

	2017	2016	Change		2016	2015	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 769	$ 764	$ 5	1%	$ 764	$ 697	$ 67	10%
MidAmerican Funding	574	532	42	8	532	442	90	20
NV Energy	346	359	(13)	(4)	359	379	(20)	(5)
Northern Powergrid	251	342	(91)	(27)	342	422	(80)	(19)
BHE Pipeline Group	277	249	28	11	249	243	6	2
BHE Transmission	224	214	10	5	214	186	28	15
BHE Renewables[(1)]	864	179	685	*	179	124	55	44
HomeServices	149	127	22	17	127	104	23	22
BHE and Other	(584)	(224)	(360)	*	(224)	(227)	3	1
Total net income attributable to BHE shareholders	$ 2,870	$ 2,542	$ 328	13	$ 2,542	$ 2,370	$ 172	7

* Not meaningful

(1) Includes the tax attributes of disregarded entities that are not required to pay income taxes and the earnings of which are taxable directly to BHE.

Net income attributable to BHE shareholders increased $328 million for 2017 compared to 2016, including a $516 million benefit as a result of 2017 Tax Reform, partially offset by a charge of $263 million from tender offers for certain long-term debt completed in December 2017. Excluding the impacts of these items, adjusted net income attributable to BHE shareholders was $2,617 million, an increase of $75 million compared to 2016.

The increase in net income attributable to BHE shareholders was due to the following with such explanations excluding the impacts of DSM and energy efficiency programs having no impact on net income:

- PacifiCorp's net income increased $5 million, including $6 million of income from 2017 Tax Reform. Excluding the impact of 2017 Tax Reform, adjusted net income was $763 million, a decrease of $1 million compared to 2016, primarily due to higher depreciation and amortization of $26 million from additional plant placed in-service, lower AFUDC of $11 million, lower production tax credits of $11 million and higher property and other taxes of $7 million, partially offset by higher gross margins of $72 million. Gross margins increased due to higher retail customer volumes, lower natural gas-fueled generation, higher wholesale revenue and higher wheeling revenue, partially offset by higher purchased electricity costs, lower average retail rates and higher coal costs. Retail customer volumes increased 1.7% due to favorable impacts of weather across the service territory, higher commercial usage and an increase in the average number of residential and commercial customers primarily in Utah and Oregon, partially offset by lower residential usage in Utah and Oregon and lower irrigation usage.

- MidAmerican Funding's net income increased $42 million, including after-tax charges of $17 million related to the tender offer of a portion of MidAmerican Funding's 6.927% Senior Bonds due 2029 and $10 million for 2017 Tax Reform. Excluding the impacts of these items, adjusted net income was $601 million, an increase of $69 million compared to 2016, primarily due to a higher income tax benefit from higher production tax credits of $38 million, the effects of ratemaking and lower pre-tax income, and higher electric gross margins of $76 million, partially offset by higher maintenance expense of $52 million due to additional wind-powered generating facilities and the timing of fossil-fueled generation maintenance, higher depreciation and amortization of $21 million due to wind-powered generation and other plant placed in-service and accruals for Iowa regulatory arrangements, partially offset by a December 2016 reduction in depreciation rates, and higher property and other taxes of $7 million. Electric gross margins increased due to higher recoveries through bill riders, higher retail customer volumes, higher wholesale revenue and higher transmission revenue, partially offset by higher coal and purchased power costs. Retail customer volumes increased 2.4% due to industrial growth net of lower residential and commercial volumes from milder temperatures.

- NV Energy's net income decreased $13 million, including a charge of $19 million from 2017 Tax Reform. Excluding the impact of 2017 Tax Reform, adjusted net income was $365 million, an increase of $6 million compared to 2016, primarily due to higher electric gross margins of $20 million and lower interest expense of $17 million from lower deferred charges and lower rates on outstanding debt balances, partially offset by $28 million of charges related to the Nevada Power regulatory rate order. Electric gross margins increased due to higher retail customer volumes, partially offset by a decrease in wholesale revenues. Retail customer volumes increased 1.5% due to customer usage patterns, higher customer demand from the impacts of weather and an increase in the average number of customers.

- Northern Powergrid's net income decreased $91 million due to higher income tax expense of $35 million primarily due to $39 million of benefits from the resolution of income tax return claims in 2016 and $17 million of deferred income tax benefits reflected in 2016 due to a 1% reduction in the United Kingdom corporate income tax rate, higher pension expense of $24 million, including the impact of settlement losses recognized in 2017 due to higher lump sum payments, lower distribution revenue of $23 million and the stronger United States dollar of $11 million. These decreases were partially offset by $19 million of asset provisions recognized in 2016 at the CE Gas business. Distribution revenue decreased due to lower units distributed, the recovery in 2016 of the December 2013 customer rebate and unfavorable movements in regulatory provisions, partially offset by higher tariff rates.

- BHE Pipeline Group's net income increased $28 million, including $7 million of income from 2017 Tax Reform. Excluding the impact of 2017 Tax Reform, adjusted net income was $270 million, an increase of $21 million compared to 2016, primarily due to a reduction in expenses and regulatory liabilities related to the impact of an alternative rate structure approved by the FERC at Kern River and higher transportation and storage revenues at Northern Natural Gas, partially offset by lower transportation revenue at Kern River and higher operating expense at Northern Natural Gas.

- BHE Transmission's net income increased $10 million from higher earnings at AltaLink of $18 million, partially offset by lower earnings at BHE U.S. Transmission of $8 million. Earnings at AltaLink increased primarily due to additional assets placed in-service, lower impairments of nonregulated natural gas-fueled generation assets of $21 million and the weaker United States dollar of $3 million, partially offset by more favorable regulatory decisions in 2016. BHE U.S. Transmission's earnings decreased primarily due to lower equity earnings at Electric Transmission Texas, LLC from the impacts of a regulatory rate order in March 2017.

- BHE Renewables' net income increased $685 million, including $628 million of income from 2017 Tax Reform primarily resulting from reductions in deferred income tax liabilities. Excluding the impact of 2017 Tax Reform, adjusted net income was $236 million, an increase of $57 million compared to 2016, primarily due to additional wind and solar capacity placed in-service, higher generation at the Solar Star projects due to transformer related forced outages in 2016 and higher production at the Casecnan project due to higher rainfall.

- HomeServices' net income increased $22 million, including $31 million of income from 2017 Tax Reform. Excluding the impact of 2017 Tax Reform, adjusted net income was $118 million, a decrease of $9 million compared to 2016, primarily due to lower earnings at acquired and existing brokerage businesses, partially offset by higher earnings at existing franchise businesses.
- BHE and Other net loss increased $360 million, including after-tax charges of $246 million related to the tender offer of a portion of BHE's senior bonds and $127 million for 2017 Tax Reform. Excluding the impacts of these items, the adjusted net loss was $211 million, an improvement of $13 million compared to 2016. The $127 million of net loss from 2017 Tax Reform included an accrual for the deemed repatriation of undistributed foreign earnings and profits totaling $419 million, partially offset by $292 million of benefits from reductions in deferred income tax liabilities primarily related to the unrealized gain on the investment in BYD Company Limited.

Net income attributable to BHE shareholders increased $172 million for 2016 compared to 2015 due to the following:

- PacifiCorp's net income increased $67 million due to higher gross margins of $86 million, lower operations and maintenance expenses of $18 million, and higher production tax credits of $8 million, partially offset by higher depreciation and amortization of $13 million, lower AFUDC of $9 million and higher property taxes of $5 million. Gross margins increased primarily due to lower purchased electricity costs, higher retail rates, lower coal-fueled generation and lower natural gas costs, partially offset by lower wholesale electricity revenue from lower volumes and prices. Retail customer volumes decreased by 0.6% due to lower commercial customer usage in Utah and lower industrial customer usage primarily in Utah and Oregon, partially offset by an increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah and the impacts of weather on residential customer volumes.
- MidAmerican Funding's net income increased $90 million due to higher electric gross margins of $172 million, higher production tax credits of $39 million and lower fossil-fueled generation operations and maintenance of $35 million, partially offset by higher depreciation and amortization of $72 million from wind-powered generation and other plant placed in-service and an accrual related to an Iowa regulatory revenue sharing arrangement, a pre-tax gain of $13 million in 2015 on the sale of a generating facility lease, higher interest expense of $12 million and higher income taxes from the effects of ratemaking and higher pre-tax income. Electric gross margins reflect higher retail sales volumes, higher retail rates in Iowa, lower energy costs, higher wholesale revenue and higher transmission revenue.
- NV Energy's net income decreased $20 million due to higher operating expense of $27 million, higher depreciation and amortization of $11 million due to higher plant in-service and lower electric gross margins of $2 million, partially offset by lower interest expense of $12 million. Operating expense increased due to benefits from changes in contingent liabilities in 2015 and regulatory disallowances in 2016. Electric gross margins decreased primarily due to lower transmission and wholesale revenue and lower customer usage offset by higher customer growth.
- Northern Powergrid's net income decreased $80 million due to the stronger United States dollar of $47 million, lower distribution revenues mainly due to the recovery in 2015 of the December 2013 customer rebate and unfavorable movements in regulatory provisions, higher depreciation of $25 million from additional assets placed in service, higher write-offs of hydrocarbon well exploration costs of $15 million and higher interest expense of $7 million. These adverse variances were partially offset by higher smart meter revenue, lower operating expenses and lower income tax expense primarily due to the resolution of income tax return claims from prior years partially offset by decreased deferred income tax benefits due to a 1% reduction in the United Kingdom corporate income tax rate in 2016 compared to a 2% reduction in 2015.
- BHE Pipeline Group's net income increased $6 million due to higher storage revenues, lower operating expenses and lower interest expense due to the early redemption in December 2015 of the 6.667% Senior Notes at Kern River, partially offset by lower transportation revenues and higher depreciation expense.
- BHE Transmission's net income increased $28 million from higher earnings at AltaLink of $22 million and at BHE U.S. Transmission of $6 million. Earnings at AltaLink increased primarily due to additional assets placed in-service and favorable regulatory decisions, partially offset by a $26 million pre-tax impairment related to nonregulated natural gas-fueled generation assets and the stronger United States dollar of $5 million. BHE U.S. Transmission's earnings improved primarily from higher equity earnings at Electric Transmission Texas, LLC from continued investment and additional plant placed in-service.
- BHE Renewables' net income increased $55 million due to three tax equity investments reaching commercial operations in 2016 and higher production at wind projects, including additional capacity placed in-service in 2016 at two projects, partially offset by lower solar revenues mainly due to forced outages and higher depreciation expense due to additional wind and solar capacity placed in-service.

- HomeServices' net income increased $23 million due to a 9% increase in closed brokerage units, primarily due to acquired brokerage businesses, a 2% increase in average home sales prices and higher earnings at existing mortgage and franchise businesses.
- BHE and Other net loss improved $3 million due to lower interest expense, an increase in consolidated deferred state income tax benefits and higher investment returns, partially offset by higher United States income taxes on foreign earnings.

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):

	2017	2016	Change		2016	2015	Change	
Operating revenue:								
PacifiCorp	$ 5,237	$ 5,201	$ 36	1%	$ 5,201	$ 5,232	$ (31)	(1)%
MidAmerican Funding	2,846	2,631	215	8	2,631	2,515	116	5
NV Energy	3,015	2,895	120	4	2,895	3,351	(456)	(14)
Northern Powergrid	949	995	(46)	(5)	995	1,140	(145)	(13)
BHE Pipeline Group	993	978	15	2	978	1,016	(38)	(4)
BHE Transmission	699	502	197	39	502	592	(90)	(15)
BHE Renewables	838	743	95	13	743	728	15	2
HomeServices	3,443	2,801	642	23	2,801	2,526	275	11
BHE and Other	594	676	(82)	(12)	676	780	(104)	(13)
Total operating revenue	$ 18,614	$ 17,422	$ 1,192	7	$ 17,422	$ 17,880	$ (458)	(3)
Operating income:								
PacifiCorp	$ 1,462	$ 1,427	$ 35	2%	$ 1,427	$ 1,344	$ 83	6 %
MidAmerican Funding	562	566	(4)	(1)	566	451	115	25
NV Energy	765	770	(5)	(1)	770	812	(42)	(5)
Northern Powergrid	436	494	(58)	(12)	494	593	(99)	(17)
BHE Pipeline Group	475	455	20	4	455	464	(9)	(2)
BHE Transmission	322	92	230	*	92	260	(168)	(65)
BHE Renewables	316	256	60	23	256	255	1	—
HomeServices	214	212	2	1	212	184	28	15
BHE and Other	(38)	(21)	(17)	(81)	(21)	(35)	14	40
Total operating income	$ 4,514	$ 4,251	$ 263	6	$ 4,251	$ 4,328	$ (77)	(2)

* Not meaningful

PacifiCorp

Operating revenue increased $36 million for 2017 compared to 2016 due to higher wholesale and other revenue of $50 million, partially offset by lower retail revenue of $14 million. Wholesale and other revenue increased due to higher wholesale sales volumes and short-term market prices and higher wheeling revenue. Retail revenue decreased due to lower average rates of $64 million and lower DSM program revenue (offset in operating expense) of $55 million, primarily driven by the establishment of the Utah Sustainable Transportation and Energy Plan program, partially offset by higher customer volumes of $105 million. Retail customer volumes increased 1.7% due to impacts of weather across the service territory, higher commercial usage and an increase in the average number of residential and commercial customers primarily in Utah and Oregon, partially offset by lower residential usage in Utah and Oregon and lower irrigation usage.

Operating income increased $35 million for 2017 compared to 2016 due to higher gross margins of $72 million, excluding the impact of a decrease in DSM program revenue (offset in operating expense) of $55 million, partially offset by higher depreciation and amortization of $26 million from additional plant placed in-service and higher property and other taxes of $7 million. Gross margins increased due to higher retail customer volumes, lower natural gas-fueled generation, higher wholesale revenue and higher wheeling revenue, partially offset by higher purchased electricity costs, lower average retail rates and higher coal costs.

Operating revenue decreased $31 million for 2016 compared to 2015 due to lower wholesale and other revenue of $88 million, partially offset by higher retail revenue of $57 million. Wholesale and other revenue decreased due to lower wholesale volumes of $65 million and lower average wholesale prices of $25 million. The increase in retail revenue was primarily due to higher retail rates. Retail customer volumes decreased by 0.6% due to lower commercial customer usage in Utah and lower industrial customer usage primarily in Utah and Oregon, partially offset by an increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah and the impacts of weather on residential customer volumes.

Operating income increased $83 million for 2016 compared to 2015 due to higher margins of $86 million and lower operations and maintenance expenses of $18 million, partially offset by higher depreciation and amortization of $13 million and higher property taxes of $5 million. Margins increased due to lower energy costs of $117 million, partially offset by lower operating revenue of $31 million. Energy costs decreased primarily due to lower purchased electricity costs, lower coal-fueled generation and lower natural gas costs, partially offset by higher gas-fueled generation and higher coal costs. Operations and maintenance expenses decreased primarily due to lower plant maintenance costs associated with reduced generation and lower labor and benefit costs due to lower headcount, partially offset by a Washington rate case decision disallowing returns on recent selective catalytic reduction projects.

MidAmerican Funding

Operating revenue increased $215 million for 2017 compared to 2016 due to higher electric operating revenue of $123 million, higher natural gas operating revenue of $82 million and higher other revenue of $9 million. Electric operating revenue increased due to higher retail revenue of $88 million and higher wholesale and other revenue of $35 million. Electric retail revenue increased $73 million from higher recoveries through bill riders (substantially offset in cost of sales, operating expense and income tax expense) and $39 million from usage and growth and rate factors, including higher industrial sales volumes, partially offset by $24 million from the impact of milder temperatures in 2017. Electric retail customer volumes increased 2.4% from industrial growth, partially offset by the unfavorable impact of temperatures. Electric wholesale and other revenue increased primarily due to higher transmission revenue of $13 million, higher wholesale volumes of $12 million and higher wholesale prices of $8 million. Natural gas operating revenue increased due to a higher average per-unit cost of gas sold of $67 million (offset in cost of sales), higher DSM program revenue of $3 million (offset in operating expense), 2.4% higher wholesale sales volumes and 0.1% higher retail sales volumes.

Operating income decreased $4 million for 2017 compared to 2016 due to higher maintenance expense of $52 million for additional wind-powered generating facilities and the timing of fossil-fueled generation maintenance, higher depreciation and amortization of $21 million and higher property and other taxes of $7 million, partially offset by higher electric gross margins of $76 million, excluding the impact of an increase in electric DSM program revenue of $22 million (offset in operating expense), and higher natural gas gross margins of $5 million, excluding the impact of an increase in gas DSM program revenue of $3 million (offset in operating expense). Electric gross margins were higher due to higher recoveries through bill riders, higher retail sales volumes, higher wholesale revenue and higher transmission revenue, partially offset by higher coal-fueled generation and purchased power costs. The increase in depreciation and amortization reflects $38 million related to wind generation and other plant placed in-service and higher accruals for Iowa regulatory arrangements of $14 million, partially offset by a reduction of $31 million from lower depreciation rates implemented in December 2016.

Operating revenue increased $116 million for 2016 compared to 2015 due to higher electric operating revenue of $148 million, partially offset by lower natural gas operating revenue of $24 million and lower other operating revenue of $8 million. Electric operating revenue increased due to higher retail revenue of $112 million and higher wholesale and other revenue of $36 million. Retail revenue increased $47 million from higher electric rates in Iowa effective January 1, 2016, $33 million from non-weather-related usage factors, including higher industrial sales volumes and $30 million from warmer cooling season temperatures, net of warmer winter temperatures in 2016. Electric retail customer volumes increased 3.8% from the favorable impact of temperatures and industrial growth. Electric wholesale and other revenue increased primarily due to higher wholesale prices of $25 million and higher transmission revenue of $17 million related to Multi-Value Projects, which are expected to increase as projects are constructed, partially offset by lower wholesale volumes of $6 million. Natural gas operating revenue decreased due to a lower average per-unit cost of gas sold of $42 million, which is offset in cost of sales, and 0.5% lower retail sales volumes, primarily from warmer winter temperatures in 2016, partially offset by 10.1% higher wholesale volumes. Other operating revenue decreased primarily due to the completion of major projects of a nonregulated utility construction subsidiary in 2015.

Operating income increased $115 million for 2016 compared to 2015 due to the higher electric operating revenue, lower energy costs of $24 million reflecting lower coal-fueled generation in part due to greater wind-powered generation, higher purchased power volumes and higher natural gas-fueled generation, lower fossil-fueled generation maintenance of $24 million from planned outages in 2015 and lower generation operations costs of $7 million, partially offset by higher depreciation and amortization of $70 million from wind-powered generation and other plant placed in-service and an accrual related to an Iowa regulatory revenue sharing arrangement, higher other generation maintenance of $13 million primarily from the addition of wind turbines and higher operating expense recovered through bill riders of $14 million.

NV Energy

Operating revenue increased $120 million for 2017 compared to 2016 due to higher electric operating revenue of $134 million, partially offset by lower natural gas operating revenue of $11 million. Electric operating revenue increased due to higher retail revenue of $127 million and higher transmission revenue of $9 million. Electric retail revenue increased due to $198 million from higher rates primarily from energy costs (offset in cost of sales), $40 million from higher distribution only service revenue and impact fees received due to customers purchasing energy from alternative providers and becoming distribution only service customers, $18 million from an increase in the average number customers and $10 million higher customer usage mainly from the favorable impacts of weather, partially offset by $114 million from lower commercial and industrial revenue, mainly from customers purchasing energy from alternative providers, and $23 million of lower energy efficiency program revenue (offset in operating expense). Electric retail customer volumes, including distribution only service customers, increased 1.5% compared to 2016. Natural gas operating revenue decreased due to lower energy rates, partially offset by higher customer usage.

Operating income decreased $5 million for 2017 compared to 2016 due to $25 million of operating expenses related to Nevada Power's regulatory rate review, partially offset by higher electric gross margins of $20 million, excluding the impact of a decrease in energy efficiency program revenue (offset in operating expense) of $23 million. Electric gross margins were higher due to increased electric operating revenue of $157 million, excluding the impact of decreased energy efficiency program revenues, partially offset by increased energy costs of $137 million. Energy costs increased due to lower net deferred power costs of $85 million, a higher average cost of fuel for generation of $44 million and higher purchased power costs.

Operating revenue decreased $456 million for 2016 compared to 2015 due to lower electric operating revenue of $427 million, lower natural gas operating revenue of $27 million, primarily due to lower energy rates partially offset by higher customer usage, and lower other operating revenue of $2 million. Electric operating revenue decreased due to lower retail revenue of $414 million and lower wholesale, transmission and other revenue of $13 million. Retail revenue decreased primarily due to $431 million from lower retail rates primarily from lower energy costs which are passed on to customers through deferred energy adjustment mechanisms and $28 million from lower customer usage, partially offset by $38 million from higher customer growth, $11 million from higher customer usage primarily due to the impacts of weather and $4 million of higher energy efficiency rate revenue (offset in operating expense). Electric retail customer volumes were flat compared to 2015.

Operating income decreased $42 million for 2016 compared to 2015 due to higher operating expense of $27 million, primarily due to benefits from changes in contingent liabilities in 2015, regulatory disallowances in 2016 and higher energy efficiency program costs (offset in operating revenue), higher depreciation and amortization of $11 million due to higher plant in-service and lower electric margins of $2 million. Electric margins were lower due to the lower electric operating revenue offset by lower energy costs of $425 million. Energy costs decreased due to lower net deferred power costs of $413 million and a lower average cost of fuel for generation of $69 million, partially offset by higher purchased power costs of $57 million.

Northern Powergrid

Operating revenue decreased $46 million for 2017 compared to 2016 due to the stronger United States dollar of $48 million and lower distribution revenues of $23 million, partially offset by higher smart meter revenue of $25 million. Distribution revenue decreased primarily due to lower units distributed of $13 million, the recovery in 2016 of the December 2013 customer rebate of $10 million and unfavorable movements on regulatory provisions of $7 million, partially offset by higher tariff rates of $5 million. Operating income decreased $58 million for 2017 compared to 2016 mainly due to the stronger United States dollar of $26 million, higher pension expense of $24 million, mainly due to the 2017 settlement loss recognized due to higher lump sum payments, and the lower distribution revenue, partially offset by write-offs of hydrocarbon well exploration costs in 2016 totaling $19 million.

Operating revenue decreased $145 million for 2016 compared to 2015 due to the stronger United States dollar of $127 million, lower distribution revenues of $28 million and lower contracting revenue of $5 million, partially offset by higher smart meter revenue of $18 million. Distribution revenue decreased due to the recovery in 2015 of the December 2013 customer rebate of $22 million, lower units distributed and unfavorable movements on regulatory provisions of $8 million, partially offset by higher tariff rates. Operating income decreased $99 million for 2016 compared to 2015 mainly due to the stronger United States dollar of $61 million, the lower distribution revenue, higher depreciation expense of $25 million from additional distribution and smart meter assets placed in-service and higher write-offs of hydrocarbon well exploration costs of $15 million, partially offset by the higher smart meter revenue and lower pension costs.

BHE Pipeline Group

Operating revenue increased $15 million for 2017 compared to 2016 primarily due to higher transportation revenues of $33 million and higher gas sales of $19 million related to system and operational balancing activities (largely offset in cost of sales) at Northern Natural Gas, partially offset by lower transportation revenues of $40 million at Kern River. Operating income increased $20 million for 2017 compared to 2016 primarily due to the higher transportation revenues at Northern Natural Gas and a reduction in expenses and regulatory liabilities related to the impact of an alternative rate structure approved by the FERC at Kern River, partially offset by higher operating expenses at Northern Natural Gas.

Operating revenue decreased $38 million for 2016 compared to 2015 due to lower gas sales of $25 million at Northern Natural Gas related to system and operational balancing activities, which are largely offset in cost of sales, and a $20 million reduction in transportation revenues, partially offset by a $7 million increase in storage revenues at Northern Natural Gas. Operating income decreased $9 million for 2016 compared to 2015 due to the lower transportation revenues and higher depreciation expense, partially offset by the higher storage revenues and lower operating expenses.

BHE Transmission

Operating revenue increased $197 million for 2017 compared to 2016 primarily due to a one-time reduction of $200 million from the 2015-2016 GTA decision received in May 2016 at AltaLink, a weaker United States dollar of $19 million and $15 million from additional assets placed in service, partially offset by more favorable regulatory decisions in 2016. Operating income increased $230 million for 2017 compared to 2016 primarily due to the higher operating revenue from the 2015-2016 GTA decision that required AltaLink to refund $200 million to customers in 2016 through reduced monthly billings for the change from receiving cash during construction for the return on construction work-in-progress in rate base to recording allowance for borrowed and equity funds used during construction related to construction expenditures during the 2011 to 2014 time period. This amount is offset with higher capitalized interest and allowance for equity funds. Operating income was also favorably impacted by lower operating expense primarily due to reduced impairments of nonregulated natural gas-fueled generation assets of $21 million and a weaker United States dollar of $11 million.

Operating revenue decreased $90 million for 2016 compared to 2015 due to a one-time reduction of $200 million from the 2015-2016 GTA decision received in May 2016 at AltaLink, AltaLink's change to the flow through method of recognizing income tax expense of $45 million, which is offset in income tax expense, and the stronger United States dollar of $20 million, partially offset by $175 million from additional assets placed in-service and recovery of higher costs. Operating income decreased $168 million for 2016 compared to 2015 due to the lower operating revenues at AltaLink, a $26 million impairment related to nonregulated natural gas-fueled generation assets and the stronger United States dollar of $5 million.

BHE Renewables

Operating revenue increased $95 million for 2017 compared to 2016 due to additional wind and solar capacity placed in-service of $57 million, higher generation at the Solar Star projects of $31 million due to transformer related forced outages in 2016 and higher production at the Casecnan project of $24 million due to higher rainfall, partially offset by lower generation of $11 million at the existing wind projects due to a lower wind resource and lower generation at the Topaz project of $6 million due to a scheduled maintenance outage. Operating income increased $60 million for 2017 compared to 2016 due to the increase in operating revenue, partially offset by higher depreciation and amortization of $21 million and higher operating expense of $18 million, each primarily due to additional wind and solar capacity placed in-service. Operating expense also increased from the scope and timing of maintenance at certain geothermal plants. The higher depreciation and amortization is offset by a reduction of $8 million from the extension of the useful life of certain wind-generating facilities from 25 years to 30 years effective January 2017.

Operating revenue increased $15 million for 2016 compared to 2015 due to higher wind generation at the Pinyon Pines and Jumbo Road projects of $21 million, additional wind capacity placed in-service of $14 million, a favorable change in the valuation of a power purchase agreement derivative of $6 million and higher hydro generation of $6 million, partially offset by lower geothermal generation of $18 million and lower solar generation of $14 million mainly due to forced outages. Operating income increased $1 million for 2016 compared to 2015 due to the higher operating revenue being offset by higher depreciation expense of $14 million from additional wind and solar capacity placed in-service.

HomeServices

Operating revenue increased $642 million for 2017 compared to 2016 due to an increase from acquired businesses totaling $542 million and a 4% increase in average home sales prices for existing brokerage businesses. Operating income increased $2 million for 2017 compared to 2016 primarily due to higher earnings from franchise businesses, partially offset by lower earnings from brokerage businesses mainly due to higher operating expenses at existing businesses.

Operating revenue increased $275 million for 2016 compared to 2015 due to an increase from acquired businesses totaling $169 million, a 2% increase in closed brokerage units and a 2% increase in average home sales prices for existing brokerage businesses and $34 million of higher mortgage revenue. Operating income increased $28 million for 2016 compared to 2015 due to the higher mortgage revenue and from higher earnings from brokerage businesses mainly due to higher net revenues, partially offset by higher operating expenses.

BHE and Other

Operating revenue decreased $82 million for 2017 compared to 2016 primarily due to lower electricity and natural gas volumes and lower electricity prices at MidAmerican Energy Services, LLC. Operating loss increased $17 million for 2017 compared to 2016 primarily due to lower margins at MidAmerican Energy Services, LLC.

Operating revenue decreased $104 million for 2016 compared to 2015 primarily due to lower electricity volumes and natural gas prices at MidAmerican Energy Services, LLC. Operating loss improved $14 million for 2016 compared to 2015 primarily due to higher margins at MidAmerican Energy Services, LLC.

Consolidated Other Income and Expense Items

Interest Expense

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

	2017	2016	Change		2016	2015	Change	
Subsidiary debt	$ 1,399	$ 1,378	$ 21	2%	$ 1,378	$ 1,392	$ (14)	(1)%
BHE senior debt and other	423	411	12	3	411	408	3	1
BHE junior subordinated debentures	19	65	(46)	(71)	65	104	(39)	(38)
Total interest expense	$ 1,841	$ 1,854	$ (13)	(1)	$ 1,854	$ 1,904	$ (50)	(3)

Interest expense decreased $13 million for 2017 compared to 2016 due to repayments of BHE junior subordinated debentures of $944 million in 2017 and $2.0 billion in 2016, scheduled maturities and principal payments and early redemptions of subsidiary debt, partially offset by debt issuances at MidAmerican Funding, Northern Powergrid, AltaLink and BHE Renewables and higher short-term borrowings at BHE.

Interest expense decreased $50 million for 2016 compared to 2015 due to repayments of BHE junior subordinated debentures of $2.0 billion in 2016, scheduled maturities and principal payments and by the impact of foreign currency exchange rate movements of $23 million, partially offset by debt issuances at MidAmerican Funding, NV Energy, Northern Powergrid, AltaLink and BHE Renewables.

Capitalized Interest

Capitalized interest decreased $94 million for 2017 compared to 2016 primarily due to $96 million recorded in the second quarter of 2016 from the 2015-2016 GTA decision received in May 2016 at AltaLink, which is offset in operating revenue, and lower construction work-in-progress balances at BHE Renewables, partially offset by higher construction work-in-progress balances at MidAmerican Energy.

Capitalized interest increased $65 million for 2016 compared to 2015 primarily due to $96 million recorded in the second quarter of 2016 from the 2015-2016 GTA decision received in May 2016 at AltaLink, which is offset in operating revenue, partially offset by lower construction work-in-progress balances at AltaLink and PacifiCorp.

Allowance for Equity Funds

Allowance for equity funds decreased $82 million for 2017 compared to 2016 primarily due to $104 million recorded in the second quarter of 2016 from the 2015-2016 GTA decision received in May 2016 at AltaLink, which is offset in operating revenue, partially offset by higher construction work-in-progress balances at MidAmerican Energy.

Allowance for equity funds increased $67 million for 2016 compared to 2015 primarily due to $104 million recorded in the second quarter of 2016 from the 2015-2016 GTA decision received in May 2016 at AltaLink, which is offset in operating revenue, partially offset by lower construction work-in-progress balances at AltaLink and PacifiCorp.

Interest and Dividend Income

Interest and dividend income decreased $9 million for 2017 compared to 2016 primarily due to a lower financial asset balance at the Casecnan project and lower dividends from BYD Company Limited.

Interest and dividend income increased $13 million for 2016 compared to 2015 primarily due to a dividend from BYD Company Limited.

Other, net

Other, net decreased $434 million for 2017 compared to 2016 primarily due to charges of $439 million from tender offers related to certain long-term debt completed in December 2017.

Income Tax (Benefit) Expense

Income tax expense decreased $957 million for 2017 compared to 2016 and the effective tax rate was (22)% for 2017 and 14% for 2016. The effective tax rate decreased primarily due to the net impacts of 2017 Tax Reform of $731 million, higher production tax credits of $97 million and the favorable impacts of rate making of $33 million, partially offset by benefits from the resolution of income tax return claims in 2016 of $39 million and deferred income tax benefits of $16 million reflected in 2016 due to a 1% reduction in the United Kingdom corporate income tax rate.

The 2017 Tax Reform most notably lowered the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018, and created a one-time repatriation tax on undistributed foreign earnings and profits. The $731 million of lower income tax expense was comprised of benefits from reductions in deferred income tax liabilities of $1,150 million, partially offset by an accrual for the deemed repatriation of undistributed foreign earnings and profits totaling $419 million.

Income tax expense decreased $47 million for 2016 compared to 2015 and the effective tax rate was 14% for 2016 and 16% for 2015. The effective tax rate decreased due to higher production tax credits of $107 million, the resolution of income tax return claims from prior years of $28 million and favorable impacts of rate making of $24 million, partially offset by unfavorable United States income taxes on foreign earnings of $46 million and lower deferred income tax benefits of $23 million due to a 1% reduction in the United Kingdom corporate income tax rate in 2016 compared to a 2% reduction in 2015.

Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold based on a per kilowatt rate as prescribed pursuant to the applicable federal income tax law and are eligible for the credit for 10 years from the date the qualifying generating facilities are placed in-service. A credit of $0.024 per kilowatt hour was applied to 2017 production and a credit of $0.023 per kilowatt hour was applied to 2016 and 2015 production, respectively, which resulted in production tax credits of $495 million in 2017, $398 million in 2016 and $291 million in 2015.

Equity (Loss) Income

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

	2017	2016	Change		2016	2015	Change	
Equity (loss) income:								
ETT	$ (62)	$ 95	$ (157)	*	$ 95	$ 81	$ 14	17%
Tax equity investments	(120)	(10)	(110)	*	(10)	(1)	(9)	*
Agua Caliente	24	25	(1)	(4)%	25	24	1	4
HomeServices	6	6	—	—	6	6	—	—
Other	1	7	(6)	(86)	7	5	2	40
Total equity (loss) income	$ (151)	$ 123	$ (274)	*	$ 123	$ 115	$ 8	7

* Not meaningful

Equity (loss) income decreased $274 million for 2017 compared to 2016 primarily due to the impacts of 2017 Tax Reform, which decreased equity income by $228 million mainly due to equity earnings charges recognized totaling $154 million for amounts to be returned to the customers of equity investments in regulated entities. These investments include pass-through entities for income tax purposes and the lower equity income is entirely offset by lower income tax expense as a result of benefits from reductions in deferred income tax liabilities. Equity income also decreased due to lower pre-tax equity earnings from tax equity investments mainly due to unfavorable operating results and lower equity earnings at Electric Transmission Texas, LLC primarily due to the impacts of new retail rates effective March 2017.

Equity income increased $8 million for 2016 compared to 2015 primarily due to higher equity earnings of $14 million at Electric Transmission Texas, LLC from continued investment and additional plant placed in-service, partially offset by a pre-tax loss of $9 million from tax equity investments at BHE Renewables.

Net Income Attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests increased $12 million for 2017 compared to 2016 mainly due to higher earnings at HomeServices' franchise business.

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 Company's long-term debt may include provisions that allow BHE or its 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, 2017, the Company's total net liquidity was as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total
Cash and cash equivalents	$ 346	$ 14	$ 172	$ 62	$ 55	$ 44	$ 242	$ 935
Credit facilities[1]	3,600	1,000	909	650	203	1,054	1,635	9,051
Less:								
Short-term debt	(3,331)	(80)	—	—	—	(345)	(732)	(4,488)
Tax-exempt bond support and letters of credit	(7)	(130)	(370)	(80)	—	(7)	—	(594)
Net credit facilities	262	790	539	570	203	702	903	3,969
Total net liquidity	$ 608	$ 804	$ 711	$ 632	$ 258	$ 746	$ 1,145	$ 4,904
Credit facilities:								
Maturity dates	2018, 2020	2020	2018, 2020	2020	2020	2018, 2019, 2022	2018, 2022	

(1) Includes amounts borrowed on a short-term loan totaling $600 million at BHE that was repaid in full in January 2018.

Refer to Note 8 of the 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, 2017 and 2016 were $6.07 billion and $6.06 billion, respectively. The increase was primarily due to improved operating results, changes in working capital and the payment for the USA Power litigation in 2016, partially offset by a reduction in income tax receipts.

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $6.1 billion and $7.0 billion, respectively. The change was primarily due to lower income tax receipts of $618 million and payment for the USA Power litigation of $123 million.

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.

The 2017 Tax Reform reduces the federal corporate tax rate from 35% to 21% effective January 1, 2018, creates a one-time repatriation tax of foreign earnings and profits to be paid over the next eight years, eliminates bonus depreciation on qualifying regulated utility assets acquired after September 27, 2017 and extends and modifies the additional first-year bonus depreciation for non-regulated property. BHE's regulated subsidiaries anticipate passing the benefits of lower tax expense to customers through regulatory mechanisms. The 2017 Tax Reform and the related regulatory outcomes will result in lower revenue, income taxes and cash flow in future years. BHE does not expect the 2017 Tax Reform and related regulatory treatment to have a material adverse impact on its cash flows, subject to actual regulatory outcomes, which will be determined based on rulings by regulatory commissions expected in 2018.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates were set at 50% in 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Production tax credits were extended and phased-out for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2019. Production tax credits are maintained at full value through 2016, at 80% of the published rate in 2017, at 60% of the published rate in 2018, and 40% of the published rate in 2019. Investment tax credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). The Company's cash flows from operations are expected to benefit from PATH due to bonus depreciation on qualifying assets through 2019 and from the 2017 Tax Reform for non-regulated property through 2026, production tax credits through 2029 and investment tax credits earned on qualifying wind and solar projects through 2021, respectively. As a result of 2017 Tax Reform, bonus depreciation on qualifying assets acquired after September 27, 2017 is eliminated for regulated utility property and is extended and modified for non-regulated property. The Company believes property acquired on or before September 27, 2017 will remain subject to PATH.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2017 and 2016 were $(6.1) billion and $(5.7) billion, respectively. The change was primarily due to higher cash paid for acquisitions of $1.0 billion, partially offset by lower capital expenditures of $519 million and lower funding of tax equity 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, 2016 and 2015 were $(5.7) billion and $(6.2) billion, respectively. The change was primarily due to lower capital expenditures of $785 million, partially offset by higher funding of tax equity investments.

Acquisitions

In 2017, the Company completed various acquisitions totaling $1.1 billion, net of cash acquired. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which primarily related to residential real estate brokerage businesses, development and construction costs for the 110-megawatt Alamo 6 and the 50-megawatt Pearl solar projects, and the remaining 25% interest in the Silverhawk natural gas-fueled generation facility at Nevada Power. As a result of the various acquisitions, the Company acquired assets of $1.1 billion, assumed liabilities of $487 million and recognized goodwill of $508 million.

In 2016 and 2015, the Company completed various acquisitions totaling $66 million and $164 million, net of cash acquired, respectively. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed. The assets acquired consisted of property, plant and equipment, development and construction costs for renewable projects, other working capital items, goodwill of $50 million and $33 million, respectively, and other identifiable intangible assets. The liabilities assumed totaled $54 million and $84 million, respectively.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2017 were $274 million. Sources of cash totaled $4.1 billion and consisted of net proceeds from short-term debt of $2.4 billion and proceeds from subsidiary debt issuances totaling $1.7 billion. Uses of cash totaled $3.9 billion and consisted mainly of $2.3 billion for repayments of BHE senior debt and junior subordinated debentures, $1.0 billion for repayments of subsidiary debt and tender offer premiums paid of $435 million.

Net cash flows from financing activities for the year ended December 31, 2016 were $(690) million. Sources of cash totaled $3.2 billion and consisted mainly of proceeds from subsidiary debt totaling $2.3 billion and net proceeds from short-term debt of $880 million. Uses of cash totaled $3.9 billion and consisted mainly of $1.8 billion for repayments of subsidiary debt and repayments of BHE subordinated debt totaling $2 billion.

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

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

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which BHE and each subsidiary has access to external financing depends on a variety of factors, including its credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry and project finance markets, among other items.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Expenditures for certain assets may ultimately include acquisitions of existing assets.

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

	Historical			Forecast		
	2015	2016	2017	2018	2019	2020
PacifiCorp	$ 916	$ 903	$ 769	$ 1,212	$ 2,100	$ 1,802
MidAmerican Funding	1,448	1,637	1,776	2,396	1,711	897
NV Energy	571	529	456	524	557	448
Northern Powergrid	674	579	579	700	621	478
BHE Pipeline Group	240	226	286	435	344	234
BHE Transmission	966	466	334	243	221	292
BHE Renewables	1,034	719	323	869	86	87
HomeServices	16	20	37	48	29	29
BHE and Other	10	11	11	16	13	12
Total	$ 5,875	$ 5,090	$ 4,571	$ 6,443	$ 5,682	$ 4,279

	Historical			Forecast		
	2015	2016	2017	2018	2019	2020
Wind generation	$ 1,177	$ 1,712	$ 1,291	$ 2,662	$ 2,219	$ 1,192
Solar generation	786	69	129	36	42	18
Electric transmission	936	448	343	248	365	551
Environmental	134	70	91	104	29	53
Other growth	394	414	560	741	609	258
Operating	2,448	2,377	2,157	2,652	2,418	2,207
Total	$ 5,875	$ 5,090	$ 4,571	$ 6,443	$ 5,682	$ 4,279

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

- Wind generation includes the following:
  - Construction of wind-powered generating facilities at MidAmerican Energy totaling $657 million for 2017, $943 million for 2016 and $931 million for 2015. MidAmerican Energy placed in-service 334 MW (nominal ratings) during 2017, 600 MW (nominal ratings) during 2016 and 608 MW (nominal ratings) during 2015. In August 2016, the IUB issued an order approving ratemaking principles related to MidAmerican Energy's construction of up to 2,000 MW (nominal ratings) of additional wind-powered generating facilities, including the additions in 2017 and facilities expected to be placed in-service in 2018 and 2019. MidAmerican Energy expects to spend $1,132 million in 2018, $1,038 million in 2019 and $329 million in 2020 for these additional wind-powered generating facilities. The ratemaking principles establish a cost cap of $3.6 billion, including AFUDC, and a fixed rate of return on equity of 11.0% over the proposed 40-year useful lives of those facilities in any future Iowa rate proceeding. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. Additionally, the ratemaking principles modify the revenue sharing mechanism currently in effect. The revised sharing mechanism will be effective in 2018 and will be triggered each year by actual equity returns exceeding a weighted average return on equity for MidAmerican Energy calculated annually. Pursuant to the change in revenue sharing, MidAmerican Energy will share 100% of the revenue in excess of this trigger with customers. Such revenue sharing will reduce coal and nuclear generation rate base, which is intended to mitigate future base rate increases. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for 100% of the federal production tax credits available.
  - Construction of wind-powered generating facilities at PacifiCorp totaling $5 million for 2017 and $31 million for 2016. The new wind-powered generating facilities are expected to be placed in-service in 2020. Planned spending for the new wind-powered generating facilities totals $200 million in 2018, $421 million in 2019 and $588 million in 2020, plus approximately $300 million for an assumed vendor supplied financing transaction to be paid in 2020 that is not included in the table above. The energy production from the new wind-powered generating facilities is expected to qualify for 100% of the federal production tax credits available.
  - Construction of wind-powered generating facilities at BHE Renewables totaling $109 million for 2017, $602 million for 2016 and $246 million for 2015. BHE Renewables placed in-service 472 MW during 2016 and 300 MW during 2015. BHE Renewables anticipates costs will total an additional $734 million in 2018 for development and construction of up to 512 MW of wind-powered generating facilities.
  - Repowering certain existing wind-powered generating facilities at PacifiCorp and MidAmerican Energy totaling $520 million for 2017 and $147 million for 2016. The repowering projects entail the replacement of significant components of older turbines. Planned spending for the repowered generating facilities totals $596 million in 2018, $758 million in 2019 and $276 million in 2020. The energy production from such repowered facilities is expected to qualify for 100% of the federal production tax credits available for ten years following each facility's return to service.
- Solar generation includes the following:
  - Construction of the community solar gardens project in Minnesota totaling $121 million for 2017, $56 million for 2016 and $3 million for 2015. BHE Renewables expects to spend an additional $26 million in 2018 to complete the project, which will be comprised of 28 locations with a nominal facilities capacity of 98 MW.
  - Final construction costs for the Solar Star and Topaz Projects totaling $738 million for 2015. Both projects declared the commercial operation date in accordance with the respective power purchase agreements and achieved completion under the respective engineering, procurement and construction agreements and financing documents in 2015.
- Electric transmission includes PacifiCorp's costs associated with main grid reinforcement and the Energy Gateway Transmission Expansion Program, MidAmerican Energy's MVPs approved by the MISO for the construction of approximately 250 miles of 345 kV transmission line located in Iowa and Illinois and ALP's directly assigned projects from the AESO, .
- 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.

- Other growth includes projects to deliver power and services to new markets, new customer connections and enhancements to existing customer connections.
- Operating includes ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid and investments in routine expenditures for generation, transmission, distribution and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

The Company has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes the Company's material contractual cash obligations as of December 31, 2017 (in millions):

	Payments Due By Periods				
	2018	2019-2020	2021-2022	2023 and After	Total
BHE senior debt	$ 1,000	$ 350	$ —	$ 5,146	$ 6,496
BHE junior subordinated debentures	—	—	—	100	100
Subsidiary debt	2,431	3,427	2,724	20,198	28,780
Interest payments on long-term debt(1)	1,769	3,040	2,760	16,457	24,026
Short-term debt	4,488	—	—	—	4,488
Fuel, capacity and transmission contract commitments(1)	2,098	3,072	2,265	10,044	17,479
Construction commitments(1)	1,120	62	—	—	1,182
Operating leases and easements(1)	180	298	232	1,297	2,007
Other(1)	290	572	571	1,189	2,622
Total contractual cash obligations	$ 13,376	$ 10,821	$ 8,552	$ 54,431	$ 87,180

(1) Not reflected on the Consolidated Balance Sheets.

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

Additionally, the Company has invested in projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company has made contributions of $403 million, $584 million and $170 million in 2017, 2016 and 2015, respectively, and has commitments as of December 31, 2017, subject to satisfaction of certain specified conditions, to provide equity contributions of $265 million in 2018 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. Once a project achieves commercial operation, the Company enters into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits from the project.

Regulatory Matters

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

Quad Cities Generating Station Operating Status

Exelon Generation Company, LLC ("Exelon Generation"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, announced on June 2, 2016, its intention to shut down Quad Cities Station on June 1, 2018, as a result of Illinois not passing adequate legislation and Quad Cities Station not clearing the 2019-2020 PJM Interconnection, L.L.C. capacity auction. MidAmerican Energy expressed to Exelon Generation its desire for the continued operation of the facility through the end of its operating license in 2032 and worked with Exelon Generation on solutions to that end. In December 2016, Illinois passed legislation creating a zero emission standard, which went into effect June 1, 2017. The zero emission standard requires the Illinois Power Agency to purchase zero emission credits and recover the costs from certain ratepayers in Illinois, subject to certain limitations. The proceeds from the zero emission credits will provide Exelon Generation additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. For the nuclear assets already in rate base, MidAmerican Energy's customers will not be charged for the subsidy, and MidAmerican Energy will not receive additional revenue from the subsidy.

On February 14, 2017, two lawsuits were filed with the United States District Court for the Northern District of Illinois ("Northern District of Illinois") against the Illinois Power Agency alleging that the state’s zero emission credit program violates certain provisions of the U.S. Constitution. Both complaints argue that the Illinois zero emission credit program will distort the FERC’s energy and capacity market auction system of setting wholesale prices. As majority owner and operator of Quad Cities Station, Exelon Generation intervened and filed motions to dismiss in both lawsuits. On July 14, 2017, the Northern District of Illinois granted the motions to dismiss. On July 17, 2017, the plaintiffs filed appeals with the United States Court of Appeals for the Seventh Circuit. Parties have filed briefs and presented oral argument. MidAmerican Energy cannot predict the outcome of these lawsuits.

On January 9, 2017, the Electric Power Supply Association filed two requests with the FERC seeking to expand Minimum Offer Price Rule ("MOPR") provisions to apply to existing resources receiving zero emission credit compensation. If successful, an expanded MOPR could result in an increased risk of Quad Cities Station not clearing in future capacity auctions and Exelon Generation no longer receiving capacity revenues for the facility. As majority owner and operator of Quad Cities Station, Exelon Generation has filed protests at the FERC in response to each filing. The timing of the FERC’s decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state, local and international agencies. The Company believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations and "Liquidity and Capital Resources" for discussion of the Company's forecast environmental-related capital expenditures.

Collateral and Contingent Features

Debt of BHE and debt and preferred securities of certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

BHE and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, the applicable entities' credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2017, the Company would have been required to post $440 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 14 of Notes to Consolidated Financial Statements for a discussion of the Company's collateral requirements specific to its derivative contracts.

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 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, 2017, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.5 billion, unused revolving credit facilities of $365 million and letters of credit outstanding of $88 million. As of December 31, 2017, the Company's pro-rata share of such short- and long-term debt was $1.2 billion, unused revolving credit facilities was $151 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 the federal, state and provincial levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $3.0 billion and total regulatory liabilities were $7.5 billion as of December 31, 2017. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Regulated Businesses' regulatory assets and liabilities.

Derivatives

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate short- and long-term debt, future debt issuances and mortgage commitments. Additionally, BHE is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain and Canada. Each of BHE's business platforms has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange rate risk. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments, or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Notes 14 and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves reflect observable market quotes. As of December 31, 2017, the Company had a net derivative liability of $120 million related to contracts valued using either quoted prices or forward price curves based upon observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are important because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2017, the Company had a net derivative asset of $103 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, 2017, the Company had $119 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, 2017 includes goodwill of acquired businesses of $9.7 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, 2017. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. Refer to Note 21 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's goodwill.

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2017, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

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

Pension and Other Postretirement Benefits

Certain of the Company's subsidiaries sponsor defined benefit pension and other postretirement benefit plans that cover the majority of employees. The Company recognizes the funded status of the defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2017, the Company recognized a net liability totaling $63 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2017, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $606 million and in AOCI totaled $530 million.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. The Company believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2017.

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

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

The Company chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5.00% by 2025, at which point the rate of increase is assumed to remain constant. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and the funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (dollars in millions):

	Domestic Plans					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2017						
Benefit Obligations:						
Discount rate	$ (155)	$ 170	$ (31)	$ 34	$ (197)	$ 222
Effect on 2017 Periodic Cost:						
Discount rate	$ (2)	$ —	$ 1	$ —	$ (18)	$ 19
Expected rate of return on plan assets	(12)	12	(3)	3	(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.

It is probable the Company's regulated businesses will pass income tax benefits and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers in certain state and provincial jurisdictions. As of December 31, 2017, these amounts were recognized as a net regulatory liability of $4.0 billion and will be included in regulated rates when the temporary differences reverse.

The 2017 Tax Reform creates a one-time repatriation tax on the Company's undistributed foreign corporations' post-1986 accumulated earnings and profits. Therefore, the cumulative undistributed foreign earnings were deemed repatriated to the United States as of December 31, 2017. The Company currently does not believe the deemed repatriation has altered the Company's existing assertion that undistributed earnings will be reinvested indefinitely; however, the Company periodically evaluates its capital requirements and that conclusion could change. As a result of the 2017 Tax Reform, future undistributed earnings are not expected to be subject to tax in the United States.

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 $665 million as of December 31, 2017. 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. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

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

The table that follows summarizes the Company's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $76 million and $74 million, respectively, as of December 31, 2017 and 2016, 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, 2017:			
Not designated as hedging contracts	$ (32)	$ (18)	$ (46)
Designated as hedging contracts	(1)	35	(37)
Total commodity derivative contracts	$ (33)	$ 17	$ (83)
As of December 31, 2016			
Not designated as hedging contracts	$ (71)	$ (37)	$ (105)
Designated as hedging contracts	(16)	19	(51)
Total commodity derivative contracts	$ (87)	$ (18)	$ (156)

The settled cost of certain of the Company's commodity derivative contracts not designated as hedging contracts is included 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. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, wholesale natural gas or fuel are higher than what is included in regulated rates, including the impacts of adjustment mechanisms. As of December 31, 2017 and 2016, a net regulatory asset of $119 million and $148 million, respectively, was recorded related to the net derivative liability of $32 million and $71 million, respectively. The difference between the net regulatory asset and the net derivative liability relates primarily to a power purchase agreement derivative at BHE Renewables. For the Company's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose the Company to earnings volatility.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt, future debt issuances and mortgage commitments. 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, 2017 and 2016, the Company had short- and long-term variable-rate obligations totaling $6.4 billion and $4.2 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, 2017 and 2016.

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, 2017 and 2016, the Company had variable-to-fixed interest rate swaps with notional amounts of $679 million and $714 million, respectively, and £136 million and £0 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2017 and 2016, the Company had mortgage commitments, net, with notional amounts of $422 million and $309 million, respectively, to protect the Company against an increase in interest rates. The fair value of the Company's interest rate derivative contracts was a net derivative asset of $16 million and $10 million, respectively, as of December 31, 2017 and 2016. A hypothetical 20 basis point increase and a 20 basis point decrease in interest rates 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, 2017 and 2016, the Company's investment in BYD Company Limited common stock represented approximately 81% and 75%, respectively, of the total fair value of the Company's equity securities. The majority of the Company's remaining equity securities related to certain trust funds in which realized and unrealized gains and losses are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. The following table summarizes the Company's investment in BYD Company Limited as of December 31, 2017 and 2016 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, 2017	$ 1,961	30% increase	$ 2,549	1%
		30% decrease	1,373	(1)
As of December 31, 2016	$ 1,185	30% increase	$ 1,541	1%
		30% decrease	830	(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, 2017, 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 $409 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 $25 million in 2017.

AltaLink's functional currency is the Canadian dollar. As of December 31, 2017, 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 $312 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 $17 million in 2017.

Credit Risk

Domestic Regulated Operations

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

As of December 31, 2017, PacifiCorp's aggregate credit exposure from wholesale activities totaled $127 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2017, $125 million, or 98.5%, 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, 2017, three counterparties comprised $91 million, or 72%, of the aggregate credit exposure. The three 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, 2017.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2017, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2017, NV Energy's aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

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

Northern Powergrid

The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to supply companies. The supply companies purchase electricity from generators and traders, sell the electricity to end-use customers and 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. During 2017, RWE Npower PLC and certain of its affiliates and British Gas Trading Limited represented approximately 21% and 15%, respectively, of the total combined distribution revenue of the Northern Powergrid Distribution Companies. The industry operates in accordance with a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided the Northern Powergrid Distribution Companies have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

AltaLink

AltaLink's primary source of operating revenue is the AESO, an entity rated AA- by Standard and Poor's. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations would significantly impair AltaLink's ability to meet its existing and future obligations. Total operating revenue for AltaLink was $699 million for the year ended December 31, 2017.

BHE Renewables

BHE Renewables owns independent power projects in the United States and the Philippines that generally have separate project financing agreements. These projects source of operating revenue is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2017 and 2040. Because of the dependence generally from a single customer at each project, any material failure of the customer to fulfill its obligations would significantly impair that project's ability to meet its existing and future obligations. Total operating revenue for BHE Renewables was $838 million for the year ended December 31, 2017.

Other Energy Business

MidAmerican Energy Services, LLC ("MES") is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with financial institutions and other market participants. Credit risk may be concentrated to the extent that MES' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MES analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MES enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MES exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2017, MES' aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of December 31, 2017 and 2016, 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, 2017, and the related notes and the schedules listed in the Index at Item 15(a)(ii) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 23, 2018

We have served as the Company's auditor since 1991.

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

	As of December 31,	
	2017	**2016**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 935	$ 721
Restricted cash and short-term investments	327	211
Trade receivables, net	2,014	1,751
Income taxes receivable	334	—
Inventories	888	925
Mortgage loans held for sale	465	359
Other current assets	815	706
Total current assets	5,778	4,673
Property, plant and equipment, net	65,871	62,509
Goodwill	9,678	9,010
Regulatory assets	2,761	4,307
Investments and restricted cash and investments	4,872	3,945
Other assets	1,248	996
Total assets	$ 90,208	$ 85,440

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,	
	2017	**2016**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,519	$ 1,317
Accrued interest	488	454
Accrued property, income and other taxes	354	389
Accrued employee expenses	274	261
Short-term debt	4,488	1,869
Current portion of long-term debt	3,431	1,006
Other current liabilities	1,049	1,017
Total current liabilities	11,603	6,313
BHE senior debt	5,452	7,418
BHE junior subordinated debentures	100	944
Subsidiary debt	26,210	26,748
Regulatory liabilities	7,309	2,933
Deferred income taxes	8,242	13,879
Other long-term liabilities	2,984	2,742
Total liabilities	61,900	60,977
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	6,368	6,390
Retained earnings	22,206	19,448
Accumulated other comprehensive loss, net	(398)	(1,511)
Total BHE shareholders' equity	28,176	24,327
Noncontrolling interests	132	136
Total equity	28,308	24,463
Total liabilities and equity	$ 90,208	$ 85,440

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,		
	2017	**2016**	**2015**
Operating revenue:			
Energy	$ 15,171	$ 14,621	$ 15,354
Real estate	3,443	2,801	2,526
Total operating revenue	18,614	17,422	17,880
Operating costs and expenses:			
Energy:			
Cost of sales	4,518	4,315	5,079
Operating expense	3,773	3,707	3,732
Depreciation and amortization	2,580	2,560	2,399
Real estate	3,229	2,589	2,342
Total operating costs and expenses	14,100	13,171	13,552
Operating income	4,514	4,251	4,328
Other income (expense):			
Interest expense	(1,841)	(1,854)	(1,904)
Capitalized interest	45	139	74
Allowance for equity funds	76	158	91
Interest and dividend income	111	120	107
Other, net	(398)	36	39
Total other income (expense)	(2,007)	(1,401)	(1,593)
Income before income tax (benefit) expense and equity (loss) income	2,507	2,850	2,735
Income tax (benefit) expense	(554)	403	450
Equity (loss) income	(151)	123	115
Net income	2,910	2,570	2,400
Net income attributable to noncontrolling interests	40	28	30
Net income attributable to BHE shareholders	$ 2,870	$ 2,542	$ 2,370

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,		
	2017	**2016**	**2015**
Net income	$ 2,910	$ 2,570	$ 2,400
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $9, $11 and $17	64	(9)	52
Foreign currency translation adjustment	546	(583)	(680)
Unrealized gains (losses) on available-for-sale securities, net of tax of $270, $(19) and $129	500	(30)	225
Unrealized gains (losses) on cash flow hedges, net of tax of $(7), $13 and $(7)	3	19	(11)
Total other comprehensive income (loss), net of tax	1,113	(603)	(414)
Comprehensive income	4,023	1,967	1,986
Comprehensive income attributable to noncontrolling interests	40	28	30
Comprehensive income attributable to BHE shareholders	$ 3,983	$ 1,939	$ 1,956

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, 2014	77	$ —	$ 6,423	$ 14,513	$ (494)	$ 131	$ 20,573
Adoption of ASC 853	—	—	—	56	—	11	67
Net income	—	—	—	2,370	—	18	2,388
Other comprehensive loss	—	—	—	—	(414)	—	(414)
Distributions	—	—	—	—	—	(21)	(21)
Common stock purchases	—	—	(3)	(33)	—	—	(36)
Other equity transactions	—	—	(17)	—	—	(5)	(22)
Balance, December 31, 2015	77	—	6,403	16,906	(908)	134	22,535
Net income	—	—	—	2,542	—	14	2,556
Other comprehensive loss	—	—	—	—	(603)	—	(603)
Distributions	—	—	—	—	—	(20)	(20)
Other equity transactions	—	—	(13)	—	—	8	(5)
Balance, December 31, 2016	77	—	6,390	19,448	(1,511)	136	24,463
Net income	—	—	—	2,870	—	22	2,892
Other comprehensive income	—	—	—	—	1,113	—	1,113
Distributions	—	—	—	—	—	(22)	(22)
Common stock purchases	—	—	(1)	(18)	—	—	(19)
Common stock exchange	—	—	(6)	(94)	—	—	(100)
Other equity transactions	—	—	(15)	—	—	(4)	(19)
Balance, December 31, 2017	77	$ —	$ 6,368	$ 22,206	$ (398)	$ 132	$ 28,308

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,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 2,910	$ 2,570	$ 2,400
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss (gain) on other items, net	455	62	(8)
Depreciation and amortization	2,646	2,591	2,428
Allowance for equity funds	(76)	(158)	(91)
Equity loss (income), net of distributions	260	(67)	(38)
Changes in regulatory assets and liabilities	31	(34)	356
Deferred income taxes and amortization of investment tax credits	19	1,090	1,265
Other, net	(2)	(142)	19
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(86)	(158)	(9)
Derivative collateral, net	(22)	32	(14)
Pension and other postretirement benefit plans	(91)	(79)	(11)
Accrued property, income and other taxes	(28)	377	877
Accounts payable and other liabilities	50	(28)	(194)
Net cash flows from operating activities	6,066	6,056	6,980
Cash flows from investing activities:			
Capital expenditures	(4,571)	(5,090)	(5,875)
Acquisitions, net of cash acquired	(1,113)	(66)	(164)
Increase in restricted cash and investments	(81)	(36)	(28)
Purchases of available-for-sale securities	(190)	(141)	(144)
Proceeds from sales of available-for-sale securities	202	191	142
Equity method investments	(368)	(570)	(202)
Other, net	(12)	(34)	41
Net cash flows from investing activities	(6,133)	(5,746)	(6,230)
Cash flows from financing activities:			
Repayments of BHE senior debt and junior subordinated debentures	(2,323)	(2,000)	(850)
Common stock purchases	(19)	—	(36)
Proceeds from subsidiary debt	1,763	2,327	2,479
Repayments of subsidiary debt	(1,000)	(1,831)	(1,354)
Net proceeds from (repayments of) short-term debt	2,361	879	(421)
Tender offer premium paid	(435)	—	—
Other, net	(73)	(65)	(73)
Net cash flows from financing activities	274	(690)	(255)
Effect of exchange rate changes	7	(7)	(4)
Net change in cash and cash equivalents	214	(387)	491
Cash and cash equivalents at beginning of period	721	1,108	617
Cash and cash equivalents at end of period	$ 935	$ 721	$ 1,108

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 a highly diversified portfolio of locally managed businesses principally engaged in the energy industry (collectively with its subsidiaries, the "Company") and is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized as eight business segments: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), NV Energy, Inc. ("NV Energy") (which primarily consists of Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific")), Northern Powergrid Holdings Company ("Northern Powergrid") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which consists of Northern Natural Gas Company ("Northern Natural Gas") and Kern River Gas Transmission Company ("Kern River")), BHE Transmission (which consists of BHE Canada Holdings Corporation ("AltaLink") (which primarily consists of AltaLink, L.P. ("ALP")) and BHE U.S. Transmission, LLC), BHE Renewables and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). The Company, through these locally managed and operated 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 investing in solar, wind, geothermal and hydroelectric projects, the second largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of BHE and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of any acquired entities from the date of acquisition. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; impairment of goodwill; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; fair value of assets acquired and liabilities assumed in business combinations; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, Northern Natural Gas, Kern River and ALP (the "Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit the Regulated Businesses' ability to recover their costs. The Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal, state and provincial levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative 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 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, 2017 and 2016, the allowance for doubtful accounts totaled $40 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 $352 million and $402 million as of December 31, 2017 and 2016, respectively, and materials and supplies totaling $536 million and $523 million as of December 31, 2017 and 2016, 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 $22 million and $27 million higher as of December 31, 2017 and 2016, 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 2017, 2016 and 2015, the Company did not record any material goodwill impairments.

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, 2017 and 2016, unbilled revenue was $665 million and $643 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets. Rates for energy businesses are established by regulators or contractual arrangements. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. The Company records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Real Estate Commission Revenue, Mortgage Revenue and Franchise Royalty Fees

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

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

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

Foreign Currency

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

Income Taxes

Berkshire Hathaway includes the Company in its consolidated 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. On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law which, among other items, reduces the federal corporate tax rate from 35% to 21%. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences that the Company's regulated businesses deems probable to be passed on to their customers in most state and provincial jurisdictions are charged or credited directly to a regulatory asset or liability 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 2017 Tax Reform also creates a one-time repatriation tax on the Company's undistributed foreign corporations' post-1986 accumulated earnings and profits. Therefore, the cumulative undistributed foreign earnings were deemed repatriated to the United States as of December 31, 2017. The Company currently does not believe the deemed repatriation has altered the Company's existing assertion that undistributed earnings will be reinvested indefinitely; however, the Company periodically evaluates its capital requirements and that conclusion could change. As a result of the 2017 Tax Reform, future undistributed earnings are not expected to be subject to tax in the United States.

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 February 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2018-02, which amends FASB Accounting Standards Codification ("ASC") Topic 220, "Income Statement - Reporting Comprehensive Income." The amendments in this guidance require a reclassification from accumulated other comprehensive income to retained earnings for the stranded tax effects that were created from the enactment of the 2017 Tax Reform. The reclassification is the difference between the historical income tax rates and the enacted rate for the items previously recorded in accumulated other comprehensive income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted retrospectively to each period(s) in which the effect of the change in the 2017 Tax Reform is recognized. Considering the significant components of the Company's accumulated other comprehensive income relate to (a) unrecognized amounts on retirement benefits of foreign pension plans and (b) unrealized gains on available-for-sale securities, which were reclassified as required by ASU No. 2016-01 that was adopted on January 1, 2018, the adoption of ASU No. 2018-02 will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2017, the FASB issued ASU No. 2017-12, which amends FASB ASC Topic 815, "Derivatives and Hedging." The amendments in this guidance update the hedge accounting model to enable entities to better portray the economics of their risk management activities in the financial statements, expands an entity's ability to hedge non-financial and financial risk components and reduces complexity in fair value hedges of interest rate risk. In addition, it eliminates the requirement to separately measure and report hedge ineffectiveness and generally requires the entire change in fair value of a hedging instrument to be presented in the same income statement line as the hedged item and also eases certain documentation and assessment requirements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach by means of a cumulative-effect adjustment to retained earnings as of the beginning of the fiscal year of adoption. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In March 2017, the FASB issued ASU No. 2017-07, which amends FASB ASC Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. This guidance must be adopted retrospectively for the presentation of the service cost component and the other components of net benefit cost in the statement of operations and prospectively for the capitalization of the service cost component in the balance sheet. The Company adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, “Statement of Cash Flows - Overall.” The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. The Company adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. The Company adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. In January 2018, the FASB issued ASU No. 2018-01 that provides for an optional transition practical expedient allowing companies to not have to evaluate existing land easements if they were not previously accounted for under ASC Topic 840, "Leases." This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. The Company plans to adopt this guidance effective January 1, 2019 and is currently evaluating the impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In January 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The Company adopted this guidance effective January 1, 2018 with a cumulative-effect increase to retained earnings of $1,085 million and a corresponding decrease to AOCI.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. During 2016 and 2017, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. 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 adopted this guidance effective January 1, 2018 under the modified retrospective method and the adoption will not have an impact on its Consolidated Financial Statements but will increase the disclosures included within Notes to Consolidated Financial Statements. The timing and amount of revenue recognized after adoption of the new guidance will not be different than before as a majority of revenue is recognized when the Company has the right to invoice as it corresponds directly with the value to the customer of the Company's performance to date. The Company's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by regulated energy, nonregulated energy and real estate, with further disaggregation of regulated energy by customer class and line of business and real estate by line of business.

(3) Business Acquisitions

In 2017, the Company completed various acquisitions totaling $1.1 billion, net of cash acquired. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which primarily related to residential real estate brokerage businesses, development and construction costs for the 110-megawatt Alamo 6 and the 50-megawatt Pearl solar projects, and the remaining 25% interest in the Silverhawk natural gas-fueled generation facility at Nevada Power. As a result of the various acquisitions, the Company acquired assets of $1.1 billion, assumed liabilities of $487 million and recognized goodwill of $508 million.

In 2016 and 2015, the Company completed various acquisitions totaling $66 million and $164 million, net of cash acquired, respectively. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed. The assets acquired consisted of property, plant and equipment, development and construction costs for renewable projects, other working capital items, goodwill of $50 million and $33 million, respectively, and other identifiable intangible assets. The liabilities assumed totaled $54 million and $84 million, respectively.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2017	2016
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 74,660	$ 71,536
Interstate natural gas pipeline assets	3-80 years	7,176	6,942
		81,836	78,478
Accumulated depreciation and amortization		(24,478)	(23,603)
Regulated assets, net		57,358	54,875
Nonregulated assets:			
Independent power plants	5-30 years	6,010	5,594
Other assets	3-30 years	1,489	1,002
		7,499	6,596
Accumulated depreciation and amortization		(1,542)	(1,060)
Nonregulated assets, net		5,957	5,536
Net operating assets		63,315	60,411
Construction work-in-progress		2,556	2,098
Property, plant and equipment, net		$ 65,871	$ 62,509

Construction work-in-progress includes $2.2 billion and $1.8 billion as of December 31, 2017 and 2016, respectively, related to the construction of regulated assets.

During the fourth quarter of 2016, MidAmerican Energy revised its electric and gas depreciation rates based on the results of a new depreciation study, the most significant impact of which was longer estimated useful lives for certain wind-powered generating facilities. The effect of this change was to reduce depreciation and amortization expense by $3 million in 2016 and $34 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 included in property, plant and equipment, net as of December 31, 2017 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67%	$ 1,442	$ 616	$ 12
Hunter No. 1	94	474	172	7
Hunter No. 2	60	297	106	1
Wyodak	80	469	216	1
Colstrip Nos. 3 and 4	10	247	131	4
Hermiston	50	180	81	1
Craig Nos. 1 and 2	19	365	231	3
Hayden No. 1	25	74	34	—
Hayden No. 2	13	43	21	—
Foote Creek	79	40	26	—
Transmission and distribution facilities	Various	794	238	67
Total PacifiCorp		4,425	1,872	96
MidAmerican Energy:				
Louisa No. 1	88%	807	432	8
Quad Cities Nos. 1 and 2(1)	25	698	387	20
Walter Scott, Jr. No. 3	79	617	316	8
Walter Scott, Jr. No. 4(2)	60	456	112	1
George Neal No. 4	41	307	159	1
Ottumwa No. 1	52	567	206	40
George Neal No. 3	72	425	183	7
Transmission facilities	Various	249	87	1
Total MidAmerican Energy		4,126	1,882	86
NV Energy:				
Navajo	11%	220	152	—
Valmy	50	388	233	1
Transmission facilities	Various	206	45	—
Total NV Energy		814	430	1
BHE Pipeline Group - common facilities	Various	286	169	—
Total		$ 9,651	$ 4,353	$ 183

(1) Includes amounts related to nuclear fuel.

(2) Facility in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa revenue sharing arrangements totaling $319 million and $81 million, respectively.

(6) Regulatory Matters

Regulatory Assets

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

	Weighted Average Remaining Life	2017	2016
Employee benefit plans[1]	16 years	$ 675	$ 816
Asset disposition costs	Various	387	281
Asset retirement obligations	13 years	334	301
Abandoned projects	3 years	156	159
Deferred operating costs	13 years	147	97
Deferred income taxes[2]	Various	143	1,754
Unrealized loss on regulated derivative contracts	4 years	122	154
Unamortized contract values	6 years	89	98
Deferred net power costs	2 years	58	38
Other	Various	839	759
Total regulatory assets		$ 2,950	$ 4,457
Reflected as:			
Current assets		$ 189	$ 150
Noncurrent assets		2,761	4,307
Total regulatory assets		$ 2,950	$ 4,457

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

(2) Amounts primarily represent income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

The Company had regulatory assets not earning a return on investment of $1.1 billion and $2.8 billion as of December 31, 2017 and 2016, 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	2017	2016
Deferred income taxes[(1)]	Various	$ 4,143	$ 25
Cost of removal[(2)]	27 years	2,349	2,242
Levelized depreciation	22 years	332	244
Asset retirement obligations	35 years	177	122
Impact fees	6 years	89	90
Employee benefit plans[(3)]	11 years	69	25
Deferred net power costs	2 years	8	64
Unrealized gain on regulated derivative contracts	1 year	3	6
Other	Various	341	302
Total regulatory liabilities		$ 7,511	$ 3,120
Reflected as:			
Current liabilities		$ 202	$ 187
Noncurrent liabilities		7,309	2,933
Total regulatory liabilities		$ 7,511	$ 3,120

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse. See Note 11 for further discussion of 2017 Tax Reform impacts.

(2) 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.

(3) 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.

ALP General Tariff Application ("GTA")

In November 2014, ALP filed a GTA requesting the Alberta Utilities Commission ("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 Alberta Electric System Operator. ALP amended the GTA in June 2015 to propose transmission tariff relief measures for customers and modifications to its capital structure. ALP also amended and updated the GTA in October 2015, reducing the requested revenue requirements to C$672 million for 2015 and C$704 million for 2016. In May 2016, the AUC issued its decision pertaining to the 2015-2016 GTA. ALP filed its 2015-2016 GTA compliance filing in July 2016 to comply with the AUC's decision.

The compliance filing requested the AUC to approve revenue requirements of C$599 million for 2015 and C$685 million for 2016. The decreased revenue requirements requested in the compliance filing, as compared to the 2015-2016 GTA filing updated in October 2015, were primarily due to the AUC approval of ALP's proposed immediate tariff relief of C$415 million for customers for 2015 and 2016, through (i) the discontinuance of construction work-in-progress ("CWIP") in rate base and the return to allowance for funds used during construction ("AFUDC") accounting effective January 1, 2015, resulting in a C$82 million reduction of revenue requirement and the refund of C$277 million previously collected as CWIP in rate base as part of ALP's transmission tariffs during 2011-2014 less related returns of C$12 million and (ii) a change to the flow through method for calculating income taxes for 2016, resulting in further tariff relief of C$68 million.

Operating revenue for the year ended December 31, 2016, included a one-time reduction of $200 million from the 2015-2016 GTA decision received in May 2016 at ALP. The 2015-2016 GTA decision required ALP to refund $200 million to customers in 2016 through reduced monthly billings for the change from receiving cash during construction for the return on CWIP in rate base to recording allowance for borrowed and equity funds used during construction related to construction expenditures during the 2011 to 2014 time period. This amount is offset with higher capitalized interest and allowance for equity funds in the Consolidated Statements of Operations. In addition, the decision required ALP to change to the flow through method of recognizing income tax expense effective January 1, 2016. This change reduced operating revenue by $45 million for the year ended December 31, 2016, with offsetting impacts to income tax expense in the Consolidated Statements of Operations.

(7) Investments and Restricted Cash and Investments

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

	2017	2016
Investments:		
BYD Company Limited common stock	$ 1,961	$ 1,185
Rabbi trusts	441	403
Other	124	106
Total investments	2,526	1,694
Equity method investments:		
Tax equity investments	1,025	741
Electric Transmission Texas, LLC	524	672
Bridger Coal Company	137	165
Other	148	142
Total equity method investments	1,834	1,720
Restricted cash and investments:		
Quad Cities Station nuclear decommissioning trust funds	515	460
Other	348	282
Total restricted cash and investments	863	742
Total investments and restricted cash and investments	$ 5,223	$ 4,156
Reflected as:		
Current assets	$ 351	$ 211
Noncurrent assets	4,872	3,945
Total investments and restricted cash and investments	$ 5,223	$ 4,156

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. Upon adoption of ASU No. 2016-01 effective January 1, 2018, all changes in fair value (whether realized or unrealized) will be recognized as gains or losses in the Consolidated Statements of Operations with a cumulative-effect increase to retained earnings as of the date of adoption totaling $1,085 million. The fair value of BHE's investment in BYD Company Limited common stock reflects a pre-tax unrealized gain of $1,729 million and $953 million as of December 31, 2017 and 2016, 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

The Company has invested in projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company has made contributions of $403 million, $584 million and $170 million in 2017, 2016 and 2015, respectively, pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. Once a project achieves commercial operation, the Company enters into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits from the project.

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 Nos. 1-4 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. See Note 11 for discussion of 2017 Tax Reform impacts to equity earnings recorded for the year ending December 31, 2017.

Restricted Cash and Investments

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

(8) Short-Term Debt and Credit Facilities

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

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total[1]
2017:								
Credit facilities[2]	$ 3,600	$ 1,000	$ 909	$ 650	$ 203	$ 1,054	$ 1,635	$ 9,051
Less:								
Short-term debt	(3,331)	(80)	—	—	—	(345)	(732)	(4,488)
Tax-exempt bond support and letters of credit	(7)	(130)	(370)	(80)	—	(7)	—	(594)
Net credit facilities	$ 262	$ 790	$ 539	$ 570	$ 203	$ 702	$ 903	$ 3,969
2016:								
Credit facilities	$ 2,000	$ 1,000	$ 609	$ 650	$ 185	$ 986	$ 915	$ 6,345
Less:								
Short-term debt	(834)	(270)	(99)	—	—	(289)	(377)	(1,869)
Tax-exempt bond support and letters of credit	(7)	(142)	(220)	(80)	—	(8)	—	(457)
Net credit facilities	$ 1,159	$ 588	$ 290	$ 570	$ 185	$ 689	$ 538	$ 4,019

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

(2) Includes amounts borrowed on a short-term loan totaling $600 million at BHE that was repaid in full in January 2018.

As of December 31, 2017, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

BHE has a $2.0 billion unsecured credit facility expiring in June 2020 with a one-year extension option subject to lender consent and a $1.0 billion unsecured credit facility expiring in May 2018. These credit facilities, which are for general corporate purposes and also support BHE's commercial paper program and provide for the issuance of letters of credit, have variable interest rates based on the Eurodollar rate 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.

As of December 31, 2017 and 2016, the weighted average interest rate on commercial paper borrowings outstanding was 1.74% and 0.88%, respectively. These credit facilities require that BHE's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter.

As of December 31, 2017 and 2016, BHE had $96 million and $123 million, respectively, of letters of credit outstanding, of which $7 million as of December 31, 2017 and 2016 were issued under the credit facilities. These letters of credit primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC expiring through December 2018 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

As of December 31, 2017, BHE had a $600 million term loan outstanding expiring in June 2018. The term loan had a variable interest rate based on the Eurodollar rate, plus a fixed spread, or a base rate, at BHE's option. In January 2018, BHE repaid the term loan at par plus accrued interest. As of December 31, 2017, the interest rate on the outstanding term loan was 2.27%.

PacifiCorp

PacifiCorp has a $600 million unsecured credit facility expiring in June 2020 with two one-year extension options subject to lender consent and a $400 million unsecured credit facility expiring in June 2020 with a one-year extension option subject to lender consent. 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 variable interest rates based on the Eurodollar rate or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities.

As of December 31, 2017 and 2016, the weighted average interest rate on commercial paper borrowings outstanding was 1.83% and 0.96%, respectively. These credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2017 and 2016, PacifiCorp had $230 million and $269 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2017 and 2016, $216 million and $255 million, respectively, of these letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2019 and $14 million support certain transactions required by third parties and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

MidAmerican Funding

MidAmerican Energy has a $900 million unsecured credit facility expiring in June 2020 with two one-year extension options subject to lender consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Eurodollar rate 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, 2016, the weighted average interest rate on commercial paper borrowings outstanding was 0.73%. 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 June 2020 and Sierra Pacific has a $250 million secured credit facility expiring in June 2020 each with two one-year extension options subject to lender consent. 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 the Eurodollar rate 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. These credit facilities require that each of the Nevada Utilities' 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.

Northern Powergrid

Northern Powergrid has a £150 million unsecured credit facility expiring in April 2020. The credit facility has a variable interest rate based on sterling London Interbank Offered Rate ("LIBOR") plus a spread that varies based on its credit ratings. 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.

AltaLink

ALP has a C$750 million secured revolving credit facility expiring in December 2019 with a recurring one-year extension option subject to lender consent. The credit facility, which provides support for borrowings under the unsecured commercial paper program and may also be used for general corporate purposes, 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 2019 with a recurring one-year extension option subject to lender consent. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, United States base rate, a spread above the 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.

As of December 31, 2017 and 2016, ALP had $121 million and $26 million outstanding under these facilities at a weighted average interest rate of 1.42% and 0.99%, respectively. 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.

AltaLink Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2022 and a C$200 million unsecured revolving credit facility expiring in December 2018 each with a recurring one-year extension option subject to lender consent. The credit facilities, which may be used for general corporate purposes and letters of credit to a maximum of C $10 million, have a variable interest rate based on the Canadian bank prime lending rate, United States base rate, a spread above the 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.

As of December 31, 2017 and 2016, AltaLink Investments, L.P. had $224 million and $263 million outstanding under these facilities at a weighted average interest rate of 2.40% and 1.74%, respectively. The credit facilities require 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.

HomeServices

HomeServices has a $600 million unsecured credit facility expiring in September 2022. The credit facility, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on the LIBOR or a base rate, at HomeServices' option, plus a spread that varies based on HomeServices' total net leverage ratio as of the last day of each quarter. As of December 31, 2017 and 2016, HomeServices had $292 million and $50 million, respectively, outstanding under its credit facility with a weighted average interest rate of 2.75% and 1.77%, respectively.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $1.0 billion and $565 million as of December 31, 2017 and 2016, respectively, used for mortgage banking activities that expire beginning in January 2018 through December 2018 or are due on demand. The mortgage lines of credit have variable rates based on LIBOR plus a spread. Collateral for these credit facilities is comprised of residential property being financed and is equal to the loans funded with the facilities. As of December 31, 2017 and 2016, HomeServices had $440 million and $327 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 3.60% and 2.77%, respectively.

BHE Renewables Letters of Credit

In connection with their bond offerings, Topaz and Solar Star entered into separate letter of credit and reimbursement facilities totaling $435 million and $627 million as of December 31, 2017 and 2016. Letters of credit issued under the letter of credit facilities will be used to (a) provide security under the power purchase agreement and large generator interconnection agreements, (b) fund the debt service reserve requirement and the operation and maintenance debt service reserve requirement and (c) provide security for remediation and mitigation liabilities. As of December 31, 2017 and 2016, $357 million and $599 million, respectively, of letters of credit had been issued under these facilities.

As of December 31, 2017 and 2016, certain other renewable projects collectively have letters of credit outstanding of $118 million and $106 million, respectively, primarily in support of the power purchase agreements associated with the projects.

(9) BHE Debt

Senior Debt

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

	Par Value	2017	2016
1.10% Senior Notes, due 2017	$ —	$ —	$ 400
5.75% Senior Notes, due 2018	650	650	649
2.00% Senior Notes, due 2018	350	350	349
2.40% Senior Notes, due 2020	350	349	349
3.75% Senior Notes, due 2023	500	498	497
3.50% Senior Notes, due 2025	400	398	397
8.48% Senior Notes, due 2028	301	302	477
6.125% Senior Bonds, due 2036	1,670	1,660	1,690
5.95% Senior Bonds, due 2037	550	547	547
6.50% Senior Bonds, due 2037	225	222	987
5.15% Senior Notes, due 2043	750	739	739
4.50% Senior Notes, due 2045	750	737	737
Total BHE Senior Debt	$ 6,496	$ 6,452	$ 7,818

	2017	2016
Reflected as:		
Current liabilities	$ 1,000	$ 400
Noncurrent liabilities	5,452	7,418
Total BHE Senior Debt	$ 6,452	$ 7,818

In January 2018, BHE issued $450 million of its 2.375% Senior Notes due 2021, $400 million of its 2.800% Senior Notes due 2023, $600 million of its 3.250% Senior Notes due 2028 and $750 million of its 3.800% Senior Notes due 2048. The net proceeds were used to refinance a portion of the Company's short-term indebtedness and for general corporate purposes.

In December 2017, BHE completed a cash tender offer for a portion of its 8.48% Senior Notes due 2028, 6.50% Senior Notes due 2037 and 6.125% Senior Notes due 2036. The total pre-tax costs of the tender offer of $410 million were recorded in other, net on the Consolidated Statement of Operations.

Junior Subordinated Debentures

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

	Par Value	2017	2016
Junior subordinated debentures, due 2044	$ —	$ —	$ 944
Junior subordinated debentures, due 2057	100	100	—
Total BHE junior subordinated debentures - noncurrent	$ 100	$ 100	$ 944

During 2017, BHE repaid at par value a total of $944 million, plus accrued interest, of its junior subordinated debentures due December 2044. Interest expense to Berkshire Hathaway for the years ended December 31, 2017, 2016 and 2015 was $16 million, $65 million and $104 million, respectively.

In June 2017, BHE issued $100 million of its 5.00% junior subordinated debentures due June 2057 in exchange for 181,819 shares of BHE no par value common stock held by a minority shareholder. The junior subordinated debentures are redeemable at BHE's option at any time from and after June 15, 2037, at par plus accrued and unpaid interest. Interest expense to the minority shareholder for the year ended December 31, 2017 was $3 million.

(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 AltaLink's transmission properties; and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of solar and wind generation projects 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 BHE's 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.

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, 2017, all subsidiaries were in compliance with their long-term debt covenants.

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

	Par Value	2017	2016
PacifiCorp	$ 7,061	$ 7,025	$ 7,079
MidAmerican Funding	5,319	5,259	4,592
NV Energy	4,577	4,581	4,582
Northern Powergrid	2,792	2,805	2,379
BHE Pipeline Group	800	796	990
BHE Transmission	4,348	4,334	4,058
BHE Renewables	3,636	3,594	3,674
HomeServices	247	247	—
Total subsidiary debt	$ 28,780	$ 28,641	$ 27,354
Reflected as:			
Current liabilities		$ 2,431	$ 606
Noncurrent liabilities		26,210	26,748
Total subsidiary debt		$ 28,641	$ 27,354

PacifiCorp

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

	Par Value	2017	2016
First mortgage bonds:			
2.95% to 8.53%, due through 2022	$ 1,875	$ 1,872	$ 1,872
2.95% to 8.23%, due 2023 to 2026	1,224	1,218	1,217
7.70% due 2031	300	298	298
5.25% to 6.25%, due 2034 to 2037	2,050	2,040	2,039
4.10% to 6.35%, due 2038 to 2042	1,250	1,236	1,235
Variable-rate series, tax-exempt bond obligations (2017-1.60% to 1.87%; 2016-0.69% to 0.86%):			
Due 2018 to 2020	79	79	91
Due 2018 to 2025(1)	70	70	108
Due 2024(1)(2)	143	142	142
Due 2024 to 2025(2)	50	50	50
Capital lease obligations - 8.75% to 14.61%, due through 2035	20	20	27
Total PacifiCorp	$ 7,061	$ 7,025	$ 7,079

(1) Supported by $216 million and $255 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2017 and 2016, 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 $27 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2017.

MidAmerican Funding

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

	Par Value	2017	2016
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 239	$ 216	$ 291
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (2017-1.91%, 2016-0.76%), due 2023-2047	370	368	219
First Mortgage Bonds:			
2.40%, due 2019	500	499	499
3.70%, due 2023	250	248	248
3.50%, due 2024	500	501	501
3.10%, due 2027	375	372	—
4.80%, due 2043	350	346	345
4.40%, due 2044	400	394	394
4.25%, due 2046	450	445	445
3.95%, due 2047	475	470	—
Notes:			
5.95% Series, due 2017	—	—	250
5.30% Series, due 2018	350	350	350
6.75% Series, due 2031	400	396	396
5.75% Series, due 2035	300	298	298
5.80% Series, due 2036	350	348	347
Transmission upgrade obligation, 4.45% and 3.42% due through 2035 and 2036, respectively	8	6	7
Capital lease obligations - 4.16%, due through 2020	2	2	2
Total MidAmerican Energy	5,080	5,043	4,301
Total MidAmerican Funding	$ 5,319	$ 5,259	$ 4,592

In February 2018, MidAmerican Energy issued $700 million of its 3.65% First Mortgage Bonds due August 2048.

In December 2017, MidAmerican Funding completed a cash tender offer for a portion of its 6.927% Senior Bonds. The total pre-tax costs of the tender offer of $29 million were recorded in other, net on the Consolidated Statement of Operations.

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, 2017, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $16 billion based on original cost. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt obligations bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2017 and 2016. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues and $180 million of the variable rate, tax-exempt bonds are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended.

NV Energy

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

	Par Value	2017	2016
NV Energy -			
6.250% Senior Notes, due 2020	$ 315	$ 337	$ 363
Nevada Power:			
General and refunding mortgage securities:			
6.500% Series O, due 2018	324	324	324
6.500% Series S, due 2018	499	499	498
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	359	357
6.750% Series R, due 2037	349	348	345
5.375% Series X, due 2040	250	248	247
5.450% Series Y, due 2041	250	244	236
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.800% Pollution Control Bonds Series 2017A, due 2032(1)	40	40	—
1.600% Pollution Control Bonds Series 2017, due 2036(1)	40	39	—
1.600% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	—
Variable-rate series - 1.890% to 1.928%			
Pollution Control Bonds Series 2006A, due 2032	—	—	38
Pollution Control Bonds Series 2006, due 2036	—	—	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	475	475	485
Total Nevada Power	3,107	3,088	3,066
Sierra Pacific:			
General and refunding mortgage securities:			
3.375% Series T, due 2023	250	249	248
2.600% Series U, due 2026	400	396	395
6.750% Series P, due 2037	252	256	255
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.250% Pollution Control Series 2016A, due 2029(2)	20	20	20
1.500% Gas Facilities Series 2016A, due 2031(2)	59	58	58
3.000% Gas and Water Series 2016B, due 2036(3)	60	63	64
Variable-rate series (2017 - 1.690% to 1.840%, 2016 - 0.788% to 0.800%):			
Water Facilities Series 2016C, due 2036	30	30	29
Water Facilities Series 2016D, due 2036	25	25	25
Water Facilities Series 2016E, due 2036	25	25	25
Capital and financial lease obligations (2017 - 2.700% to 10.396%, 2016 - 2.700% to 10.130%), due through 2054	34	34	34
Total Sierra Pacific	1,155	1,156	1,153
Total NV Energy	$ 4,577	$ 4,581	$ 4,582

(1) Subject to mandatory purchase by Nevada Power in May 2020 at which date the interest rate may be adjusted from time to time.

(2) Subject to mandatory purchase by Sierra Pacific in June 2019 at which date the interest rate may be adjusted from time to time.

(3) Subject to mandatory purchase by Sierra Pacific in June 2022 at which date the interest rate may be adjusted from time to time.

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities are subject to PUCN approval and are limited by available property and other provisions of the mortgage indentures for each of Nevada Power and Sierra Pacific. As of December 31, 2017, approximately $8.4 billion of Nevada Power's and $3.9 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

Northern Powergrid

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

	Par Value[(1)]	2017	2016
8.875% Bonds, due 2020	$ 135	$ 144	$ 136
9.25% Bonds, due 2020	270	279	259
3.901% to 4.586% European Investment Bank loans, due 2018 to 2022	366	366	333
7.25% Bonds, due 2022	270	279	257
2.50% Bonds due 2025	203	200	182
2.073% European Investment Bank loan, due 2025	68	69	62
2.564% European Investment Bank loans, due 2027	338	336	308
7.25% Bonds, due 2028	250	256	234
4.375% Bonds, due 2032	203	199	182
5.125% Bonds, due 2035	270	267	243
5.125% Bonds, due 2035	203	200	183
Variable-rate bond, due 2026[(2)]	216	210	—
Total Northern Powergrid	$ 2,792	$ 2,805	$ 2,379

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

(2) Amortizes semiannually and the Company has entered into an interest rate swap that fixes the interest rate on 85% of the outstanding debt. The variable interest rate as of December 31, 2017 was 2.27% while the fixed interest rate was 2.82%.

BHE Pipeline Group

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

	Par Value	2017	2016
Northern Natural Gas:			
5.75% Senior Notes, due 2018	$ 200	$ 200	$ 199
4.25% Senior Notes, due 2021	200	199	199
5.8% Senior Bonds, due 2037	150	149	149
4.1% Senior Bonds, due 2042	250	248	248
Total Northern Natural Gas	800	796	795
Kern River:			
4.893% Senior Notes, due 2018	—	—	195
Total BHE Pipeline Group	$ 800	$ 796	$ 990

In April 2017, Kern River redeemed the remaining amount of its 4.893% Senior Notes due April 2018 at a redemption price determined in accordance with the terms of the indenture. The total pre-tax costs of the early redemption of $5 million were recorded in other, net on the Consolidated Statement of Operations.

BHE Transmission

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

	Par Value[1]	2017	2016
AltaLink Investments, L.P.:			
Series 12-1 Senior Bonds, 3.674%, due 2019	$ 159	$ 162	$ 153
Series 13-1 Senior Bonds, 3.265%, due 2020	159	161	152
Series 15-1 Senior Bonds, 2.244%, due 2022	159	158	148
Total AltaLink Investments, L.P.	477	481	453
AltaLink, L.P.:			
Series 2008-1 Notes, 5.243%, due 2018	159	159	148
Series 2013-2 Notes, 3.621%, due 2020	100	99	93
Series 2012-2 Notes, 2.978%, due 2022	219	218	204
Series 2013-4 Notes, 3.668%, due 2023	398	397	371
Series 2014-1 Notes, 3.399%, due 2024	278	278	260
Series 2016-1 Notes, 2.747%, due 2026	278	277	259
Series 2006-1 Notes, 5.249%, due 2036	119	119	111
Series 2010-1 Notes, 5.381%, due 2040	100	99	93
Series 2010-2 Notes, 4.872%, due 2040	119	119	111
Series 2011-1 Notes, 4.462%, due 2041	219	218	204
Series 2012-1 Notes, 3.990%, due 2042	418	412	385
Series 2013-3 Notes, 4.922%, due 2043	278	278	260
Series 2014-3 Notes, 4.054%, due 2044	235	233	218
Series 2015-1 Notes, 4.090%, due 2045	278	277	259
Series 2016-2 Notes, 3.717%, due 2046	358	356	333
Series 2013-1 Notes, 4.446%, due 2053	199	198	186
Series 2014-2 Notes, 4.274%, due 2064	103	103	97
Total AltaLink, L.P.	3,858	3,840	3,592
Other:			
Construction Loan, 5.660%, due 2020	13	13	13
Total BHE Transmission	$ 4,348	$ 4,334	$ 4,058

(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 unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2017	2016
Fixed-rate[1]:			
CE Generation Bonds, 7.416%, due 2018	$ —	$ —	$ 67
Salton Sea Funding Corporation Bonds, 7.475%, due 2018	—	—	31
Cordova Funding Corporation Bonds, 8.48% to 9.07%, due 2019	—	—	97
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	94	93	99
Solar Star Funding Senior Notes, 3.950%, due 2035	314	310	311
Solar Star Funding Senior Notes, 5.375%, due 2035	975	965	966
Grande Prairie Wind Senior Notes, 3.860%, due 2037	408	404	414
Topaz Solar Farms Senior Notes, 5.750%, due 2039	755	745	780
Topaz Solar Farms Senior Notes, 4.875%, due 2039	219	217	229
Alamo 6 Senior Notes, 4.170%, due 2042	232	229	—
Other	19	19	22
Variable-rate[1]:			
Pinyon Pines I and II Term Loans, due 2019[2]	334	333	355
Wailuku Special Purpose Revenue Bonds, 0.90%, due 2021	—	—	7
TX Jumbo Road Term Loan, due 2025[2]	198	193	206
Marshall Wind Term Loan, due 2026[2]	88	86	90
Total BHE Renewables	$ 3,636	$ 3,594	$ 3,674

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on LIBOR plus a margin that varies during the terms of the agreements. The Company has entered into interest rate swaps that fix the interest rate on 75% of the Pinyon Pines outstanding debt and 100% of the TX Jumbo Road and Marshall Wind outstanding debt. The variable interest rate as of December 31, 2017 and 2016 was 3.32% and 2.62%, respectively, while the fixed interest rates as of December 31, 2017 and 2016 ranged from 3.21% to 3.63%.

In December 2017, Wailuku River Hydroelectric Limited Partnership redeemed the remaining amount of its variable rate Special Purpose Revenue Bonds due December 2021 at a redemption price determined in accordance with the terms of the indenture.

In July 2017, Cordova Funding Corporation redeemed the remaining amount of its 8.48% to 9.07% Series A Senior Secured Bonds due December 2019, CE Generation, LLC redeemed the remaining amount of its 7.416% Senior Secured Bonds due December 2018, and Salton Sea Funding Corporation redeemed the remaining amount of its 7.475% Senior Secured Series F Bonds due November 2018, each at redemption prices determined in accordance with the terms of the respective indentures.

The total pre-tax costs of the early redemptions of $15 million were recorded in other, net on the Consolidated Statement of Operations.

HomeServices

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

	Par Value	2017	2016
Variable-rate[1]:			
Variable-rate term loan, 2017 - 2.819%, due 2022	$ 247	$ 247	$ —

(1) Amortizes quarterly.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2018 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
BHE senior notes	$ 1,000	$ —	$ 350	$ —	$ —	$ 5,146	$ 6,496
BHE junior subordinated debentures	—	—	—	—	—	100	100
PacifiCorp	588	351	39	425	606	5,052	7,061
MidAmerican Funding	350	501	2	—	—	4,466	5,319
NV Energy	844	520	336	27	28	2,822	4,577
Northern Powergrid	66	78	483	26	501	1,638	2,792
BHE Pipeline Group	200	—	—	200	—	400	800
BHE Transmission	160	160	269	—	378	3,381	4,348
BHE Renewables	209	473	168	175	172	2,439	3,636
HomeServices	14	20	27	33	153	—	247
Totals	$ 3,431	$ 2,103	$ 1,674	$ 886	$ 1,838	$ 25,444	$ 35,376

(11) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018, the one-time repatriation tax of foreign earnings and profits and limitations on bonus depreciation for utility property. GAAP requires the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, the Company reduced deferred income tax liabilities $7,115 million. As it is probable the change in deferred taxes for the Company's regulated businesses will be passed back to customers through regulatory mechanisms, the Company increased net regulatory liabilities by $5,950 million. The reduction in deferred income tax liabilities also resulted in a decrease in deferred income tax expense of $1,150 million, mostly driven by the Company's non-regulated businesses, primarily BHE Renewables, BHE's investment in BYD Company Limited and HomeServices.

As a result of the 2017 Tax Reform, BHE's consolidated net income increased by $516 million primarily due to benefits from reductions in deferred income tax liabilities of $1,150 million, partially offset by an accrual for the deemed repatriation of undistributed foreign earnings and profits totaling $419 million and equity earnings charges totaling $228 million mainly for amounts to be returned to the customers of equity investments in regulated entities.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. The Company has recorded the impacts of the 2017 Tax Reform and believes all the impacts to be complete with the exception of the repatriation tax on foreign earnings and interpretations of the bonus depreciation rules. The Company has determined the amounts recorded and the interpretations relating to these two items to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. The Company believes the estimates for the repatriation tax to be reasonable, however, additional time is required to validate the inputs to the foreign earnings and profits calculation, the basis on which the repatriation tax is determined, and additional guidance is required to determine state income tax implications. The Company also believes its interpretations for bonus depreciation to be reasonable, however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

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

	2017	2016	2015
Current:			
Federal	$ (653)	$ (743)	$ (929)
State	(3)	1	29
Foreign	83	55	84
	(573)	(687)	(816)
Deferred:			
Federal	(76)	1,164	1,310
State	100	(59)	(53)
Foreign	2	(7)	17
	26	1,098	1,274
Investment tax credits	(7)	(8)	(8)
Total	$ (554)	$ 403	$ 450

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

	2017	2016	2015
Federal statutory income tax rate	35 %	35%	35%
Income tax credits	(20)	(14)	(11)
State income tax, net of federal income tax benefit	3	(1)	(1)
Effects of tax rate change and repatriation tax	(31)	—	—
Income tax effect of foreign income	(5)	(6)	(7)
Equity income	(2)	2	2
Other, net	(2)	(2)	(2)
Effective income tax rate	(22)%	14%	16%

Effects of 2017 Tax Reform have been included in state income tax, net of federal income tax benefit, effects of tax rate change and repatriation tax and equity income.

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

Income tax effect of foreign income includes, among other items, deferred income tax benefits of $16 million in 2016 and $39 million in 2015 related to the enactment of reductions in the United Kingdom corporate income tax rate. In September 2016, the corporate income tax rate was reduced from 18% to 17% effective April 1, 2020. In November 2015, the corporate income tax rate was reduced from 20% to 19% effective April 1, 2017, with a further reduction to 18% effective April 1, 2020.

Berkshire Hathaway includes the Company in its United States federal income tax return. As of December 31, 2017, the Company had current income taxes receivable from Berkshire Hathaway of $334 million. As of December 31, 2016, the Company had current income taxes payable to Berkshire Hathaway of $27 million.

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

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 1,707	$ 909
Federal, state and foreign carryforwards	1,118	987
AROs	223	326
Employee benefits	45	209
Derivative contracts	2	29
Other	448	707
Total deferred income tax assets	3,543	3,167
Valuation allowances	(126)	(64)
Total deferred income tax assets, net	3,417	3,103
Deferred income tax liabilities:		
Property-related items	(9,950)	(14,237)
Investments	(843)	(962)
Regulatory assets	(651)	(1,449)
Other	(215)	(334)
Total deferred income tax liabilities	(11,659)	(16,982)
Net deferred income tax liability	$ (8,242)	$ (13,879)

The following table provides the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2017 (in millions):

	Federal	State	Foreign	Total
Net operating loss carryforwards[(1)]	$ 172	$ 10,813	$ 605	$ 11,590
Deferred income taxes on net operating loss carryforwards	$ 37	$ 858	$ 163	$ 1,058
Expiration dates	2023-2025	2018-2037	2035-2037	
Tax credits	$ 31	$ 29	$ —	$ 60
Expiration dates	2023-indefinite	2018-indefinite		

(1) The federal net operating loss carryforwards relate principally to net operating loss carryforwards of subsidiaries that are tax residents in both the United States and the United Kingdom. The federal net operating loss carryforwards were generated prior to Berkshire Hathaway Inc.'s ownership and will begin to expire in 2023.

The United States Internal Revenue Service has closed its examination of the Company's income tax returns through December 31, 2009. State tax agencies have closed their examinations of, or the statute of limitations has expired for, the Company's income tax returns through December 31, 2005, for California and Utah, through December 31, 2007 for Kansas and Minnesota, through December 31, 2008 for Illinois, through December 31, 2009 for Idaho, Montana, Nebraska and Oregon and through December 31, 2013 for Iowa. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the examination is not closed.

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):

	2017	2016
Beginning balance	$ 128	$ 198
Additions based on tax positions related to the current year	6	7
Additions for tax positions of prior years	70	6
Reductions for tax positions of prior years	(18)	(11)
Statute of limitations	(4)	(1)
Settlements	(1)	(67)
Interest and penalties	—	(4)
Ending balance	$ 181	$ 128

As of December 31, 2017 and 2016, the Company had unrecognized tax benefits totaling $158 million and $104 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

PacifiCorp, MidAmerican Energy and NV Energy 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. PacifiCorp, MidAmerican Energy and NV Energy 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		
	2017	2016	2015	2017	2016	2015
Service cost	$ 24	$ 29	$ 33	$ 9	$ 9	$ 11
Interest cost	116	126	121	29	31	31
Expected return on plan assets	(160)	(160)	(169)	(40)	(41)	(45)
Net amortization	25	46	53	(14)	(12)	(11)
Net periodic benefit cost (credit)	$ 5	$ 41	$ 38	$ (16)	$ (13)	$ (14)

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	
	2017	2016	2017	2016
Plan assets at fair value, beginning of year	$ 2,525	$ 2,489	$ 666	$ 662
Employer contributions	64	78	5	2
Participant contributions	—	—	10	10
Actual return on plan assets	390	163	106	41
Settlement	(15)	(11)	—	—
Benefits paid	(203)	(194)	(51)	(49)
Plan assets at fair value, end of year	$ 2,761	$ 2,525	$ 736	$ 666

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

	Pension		Other Postretirement	
	2017	2016	2017	2016
Benefit obligation, beginning of year	$ 2,952	$ 2,934	$ 734	$ 740
Service cost	24	29	9	9
Interest cost	116	126	29	31
Participant contributions	—	—	10	10
Actuarial loss (gain)	132	67	(10)	(7)
Amendment	—	1	—	—
Settlement	(15)	(11)	—	—
Benefits paid	(203)	(194)	(51)	(49)
Benefit obligation, end of year	$ 3,006	$ 2,952	$ 721	$ 734
Accumulated benefit obligation, end of year	$ 2,988	$ 2,929		

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	
	2017	2016	2017	2016
Plan assets at fair value, end of year	$ 2,761	$ 2,525	$ 736	$ 666
Benefit obligation, end of year	3,006	2,952	721	734
Funded status	$ (245)	$ (427)	$ 15	$ (68)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 66	$ 26	$ 32	$ 19
Other current liabilities	(14)	(15)	—	—
Other long-term liabilities	(297)	(438)	(17)	(87)
Amounts recognized	$ (245)	$ (427)	$ 15	$ (68)

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 $272 million and $242 million as of December 31, 2017 and 2016, 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	
	2017	2016	2017	2016
Fair value of plan assets	$ 2,016	$ 1,841	$ 126	$ 413
Projected benefit obligation	$ 2,327	$ 2,294	$ 143	$ 500
Accumulated benefit obligation	$ 2,316	$ 2,278		

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	
	2017	2016	2017	2016
Net loss	$ 649	$ 775	$ 14	$ 88
Prior service credit	(3)	(7)	(37)	(52)
Regulatory deferrals	(4)	(7)	7	7
Total	$ 642	$ 761	$ (16)	$ 43

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2017 and 2016 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2015	$ 729	$ (1)	$ 13	$ 741
Net loss (gain) arising during the year	76	(11)	—	65
Net prior service cost arising during the year	1	—	—	1
Net amortization	(45)	(1)	—	(46)
Total	32	(12)	—	20
Balance, December 31, 2016	761	(13)	13	761
Net (gain) loss arising during the year	(68)	(29)	3	(94)
Net amortization	(28)	(1)	4	(25)
Total	(96)	(30)	7	(119)
Balance, December 31, 2017	$ 665	$ (43)	$ 20	$ 642

	Regulatory Asset	Regulatory Liability	Total
Other Postretirement			
Balance, December 31, 2015	$ 49	$ (12)	$ 37
Net gain arising during the year	(5)	(1)	(6)
Net amortization	11	1	12
Total	6	—	6
Balance, December 31, 2016	55	(12)	43
Net gain arising during the year	(52)	(21)	(73)
Net amortization	7	7	14
Total	(45)	(14)	(59)
Balance, December 31, 2017	$ 10	$ (26)	$ (16)

The net loss, prior service credit and regulatory deferrals that will be amortized in 2018 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 32	$ (1)	$ (3)	$ 28
Other postretirement	1	(15)	1	(13)
Total	$ 33	$ (16)	$ (2)	$ 15

Plan Assumptions

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

	Pension			Other Postretirement		
	2017	2016	2015	2017	2016	2015
Benefit obligations as of December 31:						
Discount rate	3.60%	4.06%	4.43%	3.57%	4.01%	4.33%
Rate of compensation increase	2.75%	2.75%	2.75%	NA	NA	NA
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.06%	4.43%	4.00%	4.01%	4.33%	3.93%
Expected return on plan assets	6.55%	6.78%	6.88%	6.73%	7.03%	7.00%
Rate of compensation increase	2.75%	2.75%	2.75%	NA	NA	NA

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

	2017	2016
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.10%	7.40%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2025

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

	One Percentage-Point	
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2017	$ —	$ —
Other postretirement benefit obligation as of December 31, 2017	4	(4)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $39 million and $3 million, respectively, during 2018. 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 2018 through 2022 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2018	$ 226	$ 54
2019	224	55
2020	224	57
2021	222	55
2022	214	54
2023-2027	979	243

Plan Assets

Investment Policy and Asset Allocations

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

The target allocations (percentage of plan assets) for the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2017:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities[1]	33-38	33-37
Equity securities[1]	49-60	61-65
Limited partnership interests	7-12	1-3
Other	0-1	0-1
MidAmerican Energy:		
Debt securities[1]	20-50	25-45
Equity securities[1]	60-80	45-80
Real estate funds	2-8	—
Other	0-3	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, 2017:				
Cash equivalents	$ 10	$ 76	$ —	$ 86
Debt securities:				
United States government obligations	218	—	—	218
Corporate obligations	—	350	—	350
Municipal obligations	—	16	—	16
Agency, asset and mortgage-backed obligations	—	110	—	110
Equity securities:				
United States companies	622	—	—	622
International companies	136	—	—	136
Investment funds(2)	83	20	—	103
Total assets in the fair value hierarchy	$ 1,069	$ 572	$ —	1,641
Investment funds(2) measured at net asset value				1,019
Limited partnership interests(3) measured at net asset value				63
Real estate funds measured at net asset value				38
Total assets measured at fair value				$ 2,761
As of December 31, 2016:				
Cash equivalents	$ 4	$ 54	$ —	$ 58
Debt securities:				
United States government obligations	161	—	—	161
International government obligations	—	2	—	2
Corporate obligations	—	295	—	295
Municipal obligations	—	20	—	20
Agency, asset and mortgage-backed obligations	—	112	—	112
Equity securities:				
United States companies	583	—	—	583
International companies	117	—	—	117
Investment funds(2)	146	—	—	146
Total assets in the fair value hierarchy	$ 1,011	$ 483	$ —	1,494
Investment funds(2) measured at net asset value				920
Limited partnership interests(3) measured at net asset value				61
Real estate funds measured at net asset value				50
Total assets measured at fair value				$ 2,525

(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 62% and 38%, respectively, for both 2017 and 2016. Additionally, these funds are invested in United States and international securities of approximately 68% and 32%, respectively, for 2017 and 60% and 40%, respectively, for 2016.

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

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2017:				
Cash equivalents	$ 11	$ 3	$ —	$ 14
Debt securities:				
United States government obligations	20	—	—	20
Corporate obligations	—	36	—	36
Municipal obligations	—	46	—	46
Agency, asset and mortgage-backed obligations	—	29	—	29
Equity securities:				
United States companies	185	—	—	185
International companies	8	—	—	8
Investment funds	219	1	—	220
Total assets in the fair value hierarchy	$ 443	$ 115	$ —	558
Investment funds measured at net asset value				174
Limited partnership interests measured at net asset value				4
Total assets measured at fair value				$ 736
As of December 31, 2016:				
Cash equivalents	$ 18	$ 2	$ —	$ 20
Debt securities:				
United States government obligations	19	—	—	19
Corporate obligations	—	29	—	29
Municipal obligations	—	39	—	39
Agency, asset and mortgage-backed obligations	—	25	—	25
Equity securities:				
United States companies	217	—	—	217
International companies	5	—	—	5
Investment funds[2]	152	—	—	152
Total assets in the fair value hierarchy	$ 411	$ 95	$ —	506
Investment funds[2] measured at net asset value				156
Limited partnership interests[3] measured at net asset value				4
Total assets measured at fair value				$ 666

(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 68% and 32%, respectively, for 2017 and 63% and 37%, respectively, for 2016. Additionally, these funds are invested in United States and international securities of approximately 73% and 27%, respectively, for 2017 and 72% and 28%, respectively, for 2016.

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

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

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):

	2017	2016	2015
Service cost	$ 23	$ 20	$ 24
Interest cost	58	72	79
Expected return on plan assets	(100)	(110)	(116)
Settlement	31	—	—
Net amortization	63	44	62
Net periodic benefit cost	$ 75	$ 26	$ 49

Funded Status

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

	2017	2016
Plan assets at fair value, beginning of year	$ 2,169	$ 2,276
Employer contributions	58	55
Participant contributions	1	1
Actual return on plan assets	145	349
Settlement	(144)	—
Benefits paid	(68)	(115)
Foreign currency exchange rate changes	207	(397)
Plan assets at fair value, end of year	$ 2,368	$ 2,169

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

	2017	2016
Benefit obligation, beginning of year	$ 2,125	$ 2,142
Service cost	23	20
Interest cost	58	72
Participant contributions	1	1
Actuarial loss (gain)	(4)	387
Settlement	(131)	—
Benefits paid	(68)	(115)
Foreign currency exchange rate changes	197	(382)
Benefit obligation, end of year	$ 2,201	$ 2,125
Accumulated benefit obligation, end of year	$ 1,933	$ 1,858

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):

	2017	2016
Plan assets at fair value, end of year	$ 2,368	$ 2,169
Benefit obligation, end of year	2,201	2,125
Funded status	$ 167	$ 44
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 167	$ 44

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):

	2017	2016
Net loss	$ 510	$ 590

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):

	2017	2016
Balance, beginning of year	$ 590	$ 592
Net (gain) loss arising during the year	(50)	148
Settlement	(17)	—
Net amortization	(63)	(44)
Foreign currency exchange rate changes	50	(106)
Total	(80)	(2)
Balance, end of year	$ 510	$ 590

The net loss that will be amortized from accumulated other comprehensive loss in 2018 into net periodic benefit cost is estimated to be $60 million.

Plan Assumptions

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

	2017	2016	2015
Benefit obligations as of December 31:			
Discount rate	2.60%	2.70%	3.70%
Rate of compensation increase	3.45%	3.00%	2.90%
Rate of future price inflation	2.95%	3.00%	2.90%
Net periodic benefit cost for the years ended December 31:			
Discount rate	2.70%	3.70%	3.60%
Expected return on plan assets	5.00%	5.60%	5.60%
Rate of compensation increase	3.00%	2.90%	2.80%
Rate of future price inflation	3.00%	2.90%	2.80%

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £45 million during 2018. The expected benefit payments to participants in the UK Plan for 2018 through 2022 and for the five years thereafter excluding lump sum settlement elections, using the foreign currency exchange rate as of December 31, 2017, are summarized below (in millions):

2018	$	72
2019		74
2020		75
2021		77
2022		79
2023-2027		427

Plan Assets

Investment Policy and Asset Allocations

The investment policy for the UK Plan is to balance risk and return through a diversified portfolio of debt securities, equity securities, real estate and other asset classes. 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, 2017:

	%
Debt securities(1)	50-55
Equity securities(1)	35-40
Real estate funds and other	5-15

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

Fair Value Measurements

The following table presents the fair value of the UK Plan assets, by major category (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2017:				
Cash equivalents	$ 4	$ 30	$ —	$ 34
Debt securities:				
United Kingdom government obligations	870	—	—	870
Equity securities:				
Investment funds[2]	—	1,027	—	1,027
Real estate funds	—	—	230	230
Total	$ 874	$ 1,057	$ 230	2,161
Investment funds[2] measured at net asset value				207
Total assets measured at fair value				$ 2,368
As of December 31, 2016:				
Cash equivalents	$ 4	$ 83	$ —	$ 87
Debt securities:				
United Kingdom government obligations	718	—	—	718
Equity securities:				
Investment funds[2]	—	1,095	—	1,095
Real estate funds	—	—	105	105
Total	$ 722	$ 1,178	$ 105	2,005
Investment funds[2] measured at net asset value				164
Total assets measured at fair value				$ 2,169

(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 21% and 79%, respectively, for 2017 and 44% and 56%, respectively, for 2016.

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		
	2017	2016	2015
Beginning balance	$ 105	$ 204	$ 199
Actual return on plan assets still held at period end	6	10	18
Purchases (sales)	104	(80)	—
Foreign currency exchange rate changes	15	(29)	(13)
Ending balance	$ 230	$ 105	$ 204

Defined Contribution Plans

The Company sponsors various defined contribution plans covering substantially all employees. The Company's contributions vary depending on the plan, but matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. The Company's contributions to these plans were $103 million, $102 million and $90 million for the years ended December 31, 2017, 2016 and 2015, 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 $2.3 billion and $2.2 billion as of December 31, 2017 and 2016, respectively.

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

	2017	2016
Fossil fuel facilities	$ 380	$ 404
Quad Cities Station	342	343
Wind generating facilities	138	124
Offshore pipeline facilities	32	33
Solar generating facilities	19	12
Other	43	38
Total asset retirement obligations	$ 954	$ 954
Quad Cities Station nuclear decommissioning trust funds	$ 515	$ 460

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

	2017	2016
Beginning balance	$ 954	$ 921
Change in estimated costs	(18)	33
Additions	21	25
Retirements	(45)	(63)
Accretion	42	38
Ending balance	$ 954	$ 954
Reflected as:		
Other current liabilities	$ 60	$ 98
Other long-term liabilities	894	856
Total ARO liability	$ 954	$ 954

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.

Certain of the Company's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites, and as such, each subsidiary is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

The changes in estimated costs for 2017 and 2016 were primarily due to new decommissioning studies conducted by the operator of the Quad Cities Station that changed the estimated amount and timing of cash flows.

(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 PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific (collectively, the "Utilities") as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage and transmission and transportation constraints. Interest rate risk exists on variable-rate short- and long-term debt, future debt issuances and mortgage commitments. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain and Canada. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Notes 2, 6 and 15 for additional information on derivative contracts.

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

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2017:					
Not designated as hedging contracts:					
Commodity assets[1]	$ 29	$ 92	$ 6	$ 4	$ 131
Commodity liabilities[1]	(6)	—	(64)	(93)	(163)
Interest rate assets	16	—	—	—	16
Interest rate liabilities	—	—	(1)	(7)	(8)
Total	39	92	(59)	(96)	(24)
Designated as hedging contracts:					
Commodity assets	4	9	2	1	16
Commodity liabilities	(3)	(7)	(3)	(4)	(17)
Interest rate assets	—	8	—	—	8
Interest rate liabilities	—	—	—	—	—
Total	1	10	(1)	(3)	7
Total derivatives	40	102	(60)	(99)	(17)
Cash collateral receivable	—	—	18	58	76
Total derivatives - net basis	$ 40	$ 102	$ (42)	$ (41)	$ 59
As of December 31, 2016:					
Not designated as hedging contracts:					
Commodity assets[1]	$ 42	$ 86	$ 5	$ 2	$ 135
Commodity liabilities[1]	(10)	—	(46)	(150)	(206)
Interest rate assets	15	—	—	—	15
Interest rate liabilities	—	—	(4)	(6)	(10)
Total	47	86	(45)	(154)	(66)
Designated as hedging contracts:					
Commodity assets	1	—	2	3	6
Commodity liabilities	—	—	(14)	(8)	(22)
Interest rate assets	—	8	—	—	8
Interest rate liabilities	—	—	(3)	—	(3)
Total	1	8	(15)	(5)	(11)
Total derivatives	48	94	(60)	(159)	(77)
Cash collateral receivable	—	—	13	61	74
Total derivatives - net basis	$ 48	$ 94	$ (47)	$ (98)	$ (3)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of December 31, 2017 and 2016, a net regulatory asset of $119 million and $148 million, respectively, was recorded related to the net derivative liability of $32 million and $71 million, respectively. The difference between the net regulatory asset and the net derivative liability relates primarily to a power purchase agreement derivative at BHE Renewables.

Not Designated as Hedging Contracts

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

	Commodity Derivatives		
	2017	2016	2015
Beginning balance	$ 148	$ 250	$ 223
Changes in fair value recognized in net regulatory assets	53	(30)	128
Net gains (losses) reclassified to operating revenue	10	(5)	1
Net losses reclassified to cost of sales	(92)	(67)	(102)
Ending balance	$ 119	$ 148	$ 250

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 and other transactions. Certain commodity derivative contracts have settled and the fair value at the date of settlement remains in AOCI and is recognized in earnings when the forecasted transactions impact earnings. The following table reconciles the beginning and ending balances of the Company's AOCI (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	Commodity Derivatives		
	2017	2016	2015
Beginning balance	$ 16	$ 46	$ 32
Changes in fair value recognized in OCI	15	26	52
Net gains reclassified to operating revenue	1	1	9
Net losses reclassified to cost of sales	(32)	(57)	(47)
Ending balance	$ —	$ 16	$ 46

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, 2017, 2016 and 2015, hedge ineffectiveness was insignificant. As of December 31, 2017, the Company had cash flow hedges with expiration dates extending through June 2026.

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	2017	2016
Electricity purchases	Megawatt hours	4	5
Natural gas purchases	Decatherms	310	271
Fuel purchases	Gallons	—	11
Interest rate swaps	US$	679	714
Interest rate swaps	£	136	—
Mortgage commitments, net	US$	(422)	(309)

Credit Risk

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

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, 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 $145 million and $190 million as of December 31, 2017 and 2016, respectively, for which the Company had posted collateral of $74 million and $69 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, 2017 and 2016, the Company would have been required to post $56 million and $110 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, 2017:					
Assets:					
Commodity derivatives	$ 1	$ 42	$ 104	$ (29)	$ 118
Interest rate derivatives	—	15	9	—	24
Mortgage loans held for sale	—	465	—	—	465
Money market mutual funds[(2)]	685	—	—	—	685
Debt securities:					
United States government obligations	176	—	—	—	176
International government obligations	—	5	—	—	5
Corporate obligations	—	36	—	—	36
Municipal obligations	—	2	—	—	2
Equity securities:					
United States companies	288	—	—	—	288
International companies	1,968	—	—	—	1,968
Investment funds	178	—	—	—	178
	$ 3,296	$ 565	$ 113	$ (29)	$ 3,945
Liabilities:					
Commodity derivatives	$ (3)	$ (167)	$ (10)	$ 105	$ (75)
Interest rate derivatives	—	(8)	—	—	(8)
	$ (3)	$ (175)	$ (10)	$ 105	$ (83)

As of December 31, 2016:					
Assets:					
Commodity derivatives	$ 5	$ 49	$ 87	$ (22)	$ 119
Interest rate derivatives	—	16	7	—	23
Mortgage loans held for sale	—	359	—	—	359
Money market mutual funds(2)	586	—	—	—	586
Debt securities:					
United States government obligations	161	—	—	—	161
International government obligations	—	3	—	—	3
Corporate obligations	—	36	—	—	36
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
United States companies	250	—	—	—	250
International companies	1,190	—	—	—	1,190
Investment funds	147	—	—	—	147
	$ 2,339	$ 467	$ 94	$ (22)	$ 2,878
Liabilities:					
Commodity derivatives	$ (2)	$ (199)	$ (27)	$ 96	$ (132)
Interest rate derivatives	(1)	(11)	(1)	—	(13)
	$ (3)	$ (210)	$ (28)	$ 96	$ (145)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $76 million and $74 million as of December 31, 2017 and 2016, 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 following table reconciles the beginning and ending balances of the Company's assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	Commodity Derivatives			Interest Rate Derivatives			Auction Rate Securities		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Beginning balance	$ 60	$ 47	$ 51	$ 6	$ 4	$ —	$ —	$ 44	$ 45
Changes included in earnings	23	8	19	147	121	87	—	5	—
Changes in fair value recognized in OCI	(3)	(2)	(7)	—	—	—	—	8	(1)
Changes in fair value recognized in net regulatory assets	(1)	(11)	(19)	—	—	—	—	—	—
Purchases	1	1	1	4	—	—	—	—	—
Redemptions	—	—	—	—	—	—	—	(57)	—
Settlements	14	17	2	(148)	(119)	(86)	—	—	—
Transfers from Level 2	—	—	—	—	—	3	—	—	—
Ending balance	$ 94	$ 60	$ 47	$ 9	$ 6	$ 4	$ —	$ —	$ 44

The Company's long-term debt is carried at cost, including fair value adjustments and unamortized premiums, discounts and debt issuance costs as applicable, 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):

	2017		2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 35,193	$ 40,522	$ 36,116	$ 40,718

(16) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2017 are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 2,098	$ 1,637	$ 1,435	$ 1,210	$ 1,055	$ 10,044	$ 17,479
Construction commitments	1,120	57	5	—	—	—	1,182
Operating leases and easements	180	157	141	121	111	1,297	2,007
Maintenance, service and other contracts	246	249	238	231	253	1,055	2,272
	$ 3,644	$ 2,100	$ 1,819	$ 1,562	$ 1,419	$ 12,396	$ 22,940

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 renewable generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. The Utilities also have contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to their customers.

MidAmerican Energy has long-term rail transportation contracts with BNSF Railway Company ("BNSF"), an affiliate company, and Union Pacific Railroad Company for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. For the years ended December 31, 2017, 2016 and 2015, $109 million, $137 million and $185 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:

- MidAmerican Energy's construction of wind-powered generating facilities and the last of the four Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois in 2018.
- ALP's investments in directly assigned transmission projects from the AESO.
- PacifiCorp's costs associated with certain generating plant, transmission and distribution projects.

Operating Leases and Easements

The Company has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and rail cars. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company also has non-cancelable easements for land on which certain of its assets, primarily wind-powered generating facilities, are located. Rent expense on non-cancelable operating leases and easements totaled $156 million for both 2017 and 2016 and $146 million for 2015.

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.

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.

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").

Congress failed to pass legislation needed to implement the original KHSA. On April 6, 2016, PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce and other stakeholders executed an amendment to the KHSA. Consistent with the terms of the amended KHSA, on September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC"), a private, independent nonprofit 501(c)(3) organization formed by signatories of the amended KSHA, jointly filed an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities from PacifiCorp to the KRRC. Also on September 23, 2016, the KRRC filed an application with the FERC to surrender the license and decommission the facilities. The KRRC's license surrender application included a request for the FERC to refrain from acting on the surrender application until after the transfer of the license to the KRRC is effective.

Under the amended KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. The KRRC must indemnify PacifiCorp from liabilities associated with dam removal. The amended KHSA also limits PacifiCorp's contribution to facilities 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. California voters approved a water bond measure in November 2014 from which the state of California's contribution towards facilities removal costs are being drawn. In accordance with this bond measure, additional funding of up to $250 million for facilities removal costs was included in the California state budget in 2016, with the funding effective for at least five years. If facilities 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 the KRRC or an entity other than PacifiCorp for removal to proceed.

If certain conditions in the amended KHSA are not satisfied and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

As of December 31, 2017, PacifiCorp's assets included $55 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019, or December 31, 2022, depending upon the state jurisdiction.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $239 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 June 19, 2017, BHE issued $100 million of its 5.00% junior subordinated debentures due June 2057 in exchange for 181,819 shares of its common stock from certain family interests of Mr. Walter Scott, Jr. On February 17, 2017, BHE repurchased from certain family interests of Mr. Walter Scott, Jr. 35,000 shares of its common stock for $19 million. 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 May 2018 and June 2020 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 $16.9 billion as of December 31, 2017.

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 $19.4 billion as of December 31, 2017.

(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, 2014	$ (490)	$ (412)	$ 390	$ 18	$ (494)
Other comprehensive income (loss)	52	(680)	225	(11)	(414)
Balance, December 31, 2015	(438)	(1,092)	615	7	(908)
Other comprehensive income (loss)	(9)	(583)	(30)	19	(603)
Balance, December 31, 2016	(447)	(1,675)	585	26	(1,511)
Other comprehensive income (loss)	64	546	500	3	1,113
Balance, December 31, 2017	$ (383)	$ (1,129)	$ 1,085	$ 29	$ (398)

Reclassifications from AOCI to net income for the years ended December 31, 2017, 2016 and 2015 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, 2017 and 2016, consisting of $56 million of 8.061% cumulative preferred securities of Northern Electric plc., a subsidiary of Northern Powergrid, which are redeemable in the event of the revocation of Northern Electric plc.'s electricity distribution license by the Secretary of State, and $2 million of nonredeemable preferred stock of PacifiCorp.

(20) Supplemental Cash Flow Disclosures

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

	2017	2016	2015
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 1,715	$ 1,673	$ 1,764
Income taxes received, net(1)	$ 540	$ 1,016	$ 1,666
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 653	$ 547	$ 718
Common stock exchanged for junior subordinated debentures	$ 100	$ —	$ —

(1) Includes $636 million, $1.1 billion and $1.8 billion of income taxes received from Berkshire Hathaway in 2017, 2016 and 2015, respectively.

(21) Segment Information

The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, BHE Transmission, whose business includes operations in Canada, and BHE Renewables, whose business includes operations in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2017	2016	2015
Operating revenue:			
PacifiCorp	$ 5,237	$ 5,201	$ 5,232
MidAmerican Funding	2,846	2,631	2,515
NV Energy	3,015	2,895	3,351
Northern Powergrid	949	995	1,140
BHE Pipeline Group	993	978	1,016
BHE Transmission	699	502	592
BHE Renewables	838	743	728
HomeServices	3,443	2,801	2,526
BHE and Other[1]	594	676	780
Total operating revenue	$ 18,614	$ 17,422	$ 17,880
Depreciation and amortization:			
PacifiCorp	$ 796	$ 783	$ 780
MidAmerican Funding	500	479	407
NV Energy	422	421	410
Northern Powergrid	214	200	202
BHE Pipeline Group	159	206	204
BHE Transmission	239	241	185
BHE Renewables	251	230	216
HomeServices	66	31	29
BHE and Other[1]	(1)	—	(5)
Total depreciation and amortization	$ 2,646	$ 2,591	$ 2,428
Operating income:			
PacifiCorp	$ 1,462	$ 1,427	$ 1,344
MidAmerican Funding	562	566	451
NV Energy	765	770	812
Northern Powergrid	436	494	593
BHE Pipeline Group	475	455	464
BHE Transmission	322	92	260
BHE Renewables	316	256	255
HomeServices	214	212	184
BHE and Other[1]	(38)	(21)	(35)
Total operating income	4,514	4,251	4,328
Interest expense	(1,841)	(1,854)	(1,904)
Capitalized interest	45	139	74
Allowance for equity funds	76	158	91
Interest and dividend income	111	120	107
Other, net	(398)	36	39
Total income before income tax (benefit) expense and equity (loss) income	$ 2,507	$ 2,850	$ 2,735

	Years Ended December 31,		
	2017	2016	2015
Interest expense:			
PacifiCorp	$ 381	$ 381	$ 383
MidAmerican Funding	237	218	206
NV Energy	233	250	262
Northern Powergrid	133	136	145
BHE Pipeline Group	43	50	66
BHE Transmission	169	153	146
BHE Renewables	204	198	193
HomeServices	7	2	3
BHE and Other[1]	434	466	500
Total interest expense	$ 1,841	$ 1,854	$ 1,904
Income tax (benefit) expense:			
PacifiCorp	$ 362	$ 341	$ 328
MidAmerican Funding	(202)	(139)	(150)
NV Energy	221	200	207
Northern Powergrid	57	22	35
BHE Pipeline Group	170	163	158
BHE Transmission	(124)	26	63
BHE Renewables[2]	(795)	(32)	41
HomeServices	49	81	72
BHE and Other[1]	(292)	(259)	(304)
Total income tax (benefit) expense	$ (554)	$ 403	$ 450
Capital expenditures:			
PacifiCorp	$ 769	$ 903	$ 916
MidAmerican Funding	1,776	1,637	1,448
NV Energy	456	529	571
Northern Powergrid	579	579	674
BHE Pipeline Group	286	226	240
BHE Transmission	334	466	966
BHE Renewables	323	719	1,034
HomeServices	37	20	16
BHE and Other	11	11	10
Total capital expenditures	$ 4,571	$ 5,090	$ 5,875

	As of December 31,		
	2017	2016	2015
Property, plant and equipment, net:			
PacifiCorp	$ 19,203	$ 19,162	$ 19,039
MidAmerican Funding	14,221	12,835	11,737
NV Energy	9,770	9,825	9,767
Northern Powergrid	6,075	5,148	5,790
BHE Pipeline Group	4,587	4,423	4,345
BHE Transmission	6,330	5,810	5,301
BHE Renewables	5,637	5,302	4,805
HomeServices	117	78	70
BHE and Other	(69)	(74)	(85)
Total property, plant and equipment, net	$ 65,871	$ 62,509	$ 60,769
Total assets:			
PacifiCorp	$ 23,086	$ 23,563	$ 23,550
MidAmerican Funding	18,444	17,571	16,315
NV Energy	13,903	14,320	14,656
Northern Powergrid	7,565	6,433	7,317
BHE Pipeline Group	5,134	5,144	4,953
BHE Transmission	9,009	8,378	7,553
BHE Renewables	7,687	7,010	5,892
HomeServices	2,722	1,776	1,705
BHE and Other	2,658	1,245	1,677
Total assets	$ 90,208	$ 85,440	$ 83,618

	Years Ended December 31,		
	2017	2016	2015
Operating revenue by country:			
United States	$ 16,916	$ 15,895	$ 16,121
United Kingdom	948	995	1,140
Canada	699	506	600
Philippines and other	51	26	19
Total operating revenue by country	$ 18,614	$ 17,422	$ 17,880
Income before income tax (benefit) expense and equity (loss) income by country:			
United States	$ 1,927	$ 2,264	$ 2,034
United Kingdom	313	382	472
Canada	167	135	165
Philippines and other	100	69	64
Total income before income tax (benefit) expense and equity (loss) income by country:	$ 2,507	$ 2,850	$ 2,735

	As of December 31,		
	2017	2016	2015
Property, plant and equipment, net by country:			
United States	$ 53,579	$ 51,671	$ 49,680
United Kingdom	5,953	5,020	5,757
Canada	6,323	5,803	5,298
Philippines and other	16	15	34
Total property, plant and equipment, net by country	$ 65,871	$ 62,509	$ 60,769

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, including MidAmerican Energy Services, LLC, corporate functions and intersegment eliminations.

(2) Income tax (benefit) expense includes the tax attributes of disregarded entities that are not required to pay income taxes and the earnings of which are taxable directly to BHE.

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2017 and 2016 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	Home-Services	BHE and Other	Total
December 31, 2015	$ 1,129	$ 2,102	$ 2,369	$ 1,056	$ 101	$ 1,428	$ 95	$ 794	$ 2	$9,076
Acquisitions	—	—	—	—	—	4	—	46	—	50
Foreign currency translation	—	—	—	(126)	—	42	—	—	(2)	(86)
Other	—	—	—	—	(26)	(4)	—	—	—	(30)
December 31, 2016	1,129	2,102	2,369	930	75	1,470	95	840	—	9,010
Acquisitions	—	—	—	—	—	—	—	508	—	508
Foreign currency translation	—	—	—	61	—	101	—	—	—	162
Other	—	—	—	—	(2)	—	—	—	—	(2)
December 31, 2017	$ 1,129	$ 2,102	$ 2,369	$ 991	$ 73	$ 1,571	$ 95	$ 1,348	$ —	$9,678

PacifiCorp and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

The following table sets forth PacifiCorp's selected consolidated historical financial data, which should be read in conjunction with the information in Item 7 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Consolidated Statement of Operations Data:					
Operating revenue	$ 5,237	$ 5,201	$ 5,232	$ 5,252	$ 5,147
Operating income	1,462	1,426	1,340	1,300	1,264
Net income	768	763	695	698	682

	As of December 31,				
	2017	2016	2015	2014	2013
Consolidated Balance Sheet Data:					
Total assets(1)(2)	$ 21,920	$ 22,394	$ 22,367	$ 22,205	$ 21,559
Short-term debt	80	270	20	20	—
Current portion of long-term debt and capital lease obligations	588	58	68	134	238
Long-term debt and capital lease obligations, excluding current portion(2)	6,437	7,021	7,078	6,885	6,605
Total shareholders' equity	7,555	7,390	7,503	7,756	7,787

(1) In December 2015, PacifiCorp retrospectively adopted Accounting Standards Update No. 2015-17, which resulted in the reclassification of current deferred income tax assets in the amounts of $28 million and $66 million, as of December 31, 2014 and 2013, respectively, as reductions in noncurrent deferred income tax liabilities.

(2) In December 2015, PacifiCorp retrospectively adopted Accounting Standards Update No. 2015-03, which resulted in the reclassification of certain deferred debt issuance costs previously recognized within other assets in the amounts of $34 million, as of December 31, 2014 and 2013, respectively, as reductions in long-term debt.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. PacifiCorp's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2017, was $768 million, an increase of $5 million, or 1%, compared to 2016, which includes $6 million of income from the Tax Cuts and Jobs Act enacted on December 22, 2017 (the "2017 Tax Reform"). Excluding the impact of 2017 Tax Reform, adjusted net income for the year ended December 31, 2017, was $762 million, a decrease of $1 million compared to 2016. Net income decreased primarily due to higher depreciation and amortization of $26 million from additional plant placed in-service, lower AFUDC of $11 million, higher property and other taxes of $7 million and higher operations and maintenance expenses of $3 million, excluding the impact of DSM program expense of $55 million (offset in operating revenue), partially offset by higher gross margins of $72 million, excluding the impact of DSM program revenue (offset in operations and maintenance expense) of $55 million. Gross margins increased due to higher retail customer volumes, lower natural gas-fueled generation, higher wholesale revenue from higher volumes and short-term market prices, and higher wheeling revenues, partially offset by higher purchased electricity costs, lower average retail rates, and higher coal costs. Retail customer volumes increased 1.7% due to impacts of weather across the service territory, higher commercial usage, and an increase in the average number of residential and commercial customers primarily in Utah and Oregon, partially offset by lower residential customers' usage in Utah and Oregon, and lower irrigation usage. Energy generated decreased 2% for 2017 compared to 2016 primarily due to lower natural gas-fueled and wind-power generation, partially offset by higher coal-fueled, and hydroelectric generation. Wholesale electricity sales volumes increased 9% and purchased electricity volumes increased 23%.

Net income for the year ended December 31, 2016 was $763 million, an increase of $68 million, or 10%, compared to 2015. Net income increased due to higher margins of $86 million and lower operations and maintenance expenses of $18 million, partially offset by higher depreciation and amortization of $13 million, lower AFUDC of $9 million and higher property taxes of $5 million. Margins increased primarily due to lower purchased electricity costs, higher retail revenue, lower coal-fueled generation and lower natural gas costs, partially offset by lower wholesale electricity revenue. The increase in retail revenue was primarily due to higher retail rates. Retail customer volumes decreased 0.6% due to lower commercial customer usage in Utah and lower industrial customer usage in Utah and Oregon, partially offset by an increase in the average number of residential customers in Utah and Oregon, an increase in the average number of commercial customers in Utah and the impacts of weather on residential customer volumes. Energy generated decreased 5% for 2016 compared to 2015 due to lower coal-fueled generation, partially offset by higher hydroelectric, gas-fueled and wind-powered generation. Wholesale electricity sales volumes decreased 25% and purchased electricity volumes decreased 2%.

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

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

	2017	2016	Change		2016	2015	Change	
Gross margin (in millions):								
Operating revenue	$ 5,237	$ 5,201	$ 36	1 %	$ 5,201	$ 5,232	$ (31)	(1)%
Energy costs	1,770	1,751	19	1	1,751	1,868	(117)	(6)
Gross margin	$ 3,467	$ 3,450	$ 17	—	$ 3,450	$ 3,364	$ 86	3
Sales (GWh):								
Residential	16,625	16,058	567	4 %	16,058	15,566	492	3 %
Commercial[1]	17,726	16,857	869	5	16,857	17,262	(405)	(2)
Industrial, irrigation and other[1]	20,899	21,403	(504)	(2)	21,403	21,813	(410)	(2)
Total retail	55,250	54,318	932	2	54,318	54,641	(323)	(1)
Wholesale	7,218	6,641	577	9	6,641	8,889	(2,248)	(25)
Total sales	62,468	60,959	1,509	2	60,959	63,530	(2,571)	(4)
Average number of retail customers (in thousands)	1,867	1,841	26	1 %	1,841	1,813	28	2 %
Average revenue per MWh:								
Retail	$ 87.78	$ 89.55	$ (1.77)	(2)%	$ 89.55	$ 87.99	$ 1.56	2 %
Wholesale	$ 28.56	$ 26.46	$ 2.10	8 %	$ 26.46	$ 29.92	$ (3.46)	(12)%
Sources of energy (GWh)[2]:								
Coal	37,362	36,578	784	2 %	36,578	41,298	(4,720)	(11)%
Natural gas	7,447	9,884	(2,437)	(25)	9,884	9,222	662	7
Hydroelectric[3]	4,731	3,843	888	23	3,843	2,914	929	32
Wind and other[3]	2,890	3,253	(363)	(11)	3,253	2,892	361	12
Total energy generated	52,430	53,558	(1,128)	(2)	53,558	56,326	(2,768)	(5)
Energy purchased	14,076	11,429	2,647	23	11,429	11,646	(217)	(2)
Total	66,506	64,987	1,519	2	64,987	67,972	(2,985)	(4)
Average cost of energy per MWh:								
Energy generated[4]	$ 19.14	$ 19.27	$ (0.13)	(1)%	$ 19.27	$ 19.38	$ (0.11)	(1)%
Energy purchased	$ 43.25	$ 44.64	$ (1.39)	(3)%	$ 44.64	$ 49.92	$ (5.28)	(11)%

(1) In the current year, one customer was reclassified from "Industrial, irrigation and other" into "Commercial" resulting in an increase of 61 GWh to "Commercial."

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

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

(4) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Gross margin increased $17 million, for 2017 compared to 2016 primarily due to:

- $105 million of higher retail revenues due to increased customer volumes of 1.7% due to impacts of weather across the service territory, higher commercial usage, an increase in the average number of residential and commercial customers primarily in Utah and Oregon, partially offset by lower residential usage in Utah and Oregon and lower irrigation usage;
- $54 million of higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms;
- $40 million of lower natural gas costs primarily due to lower volumes and prices in 2017;
- $30 million of higher wholesale revenue due to higher volumes and short-term market prices;
- $20 million of lower coal costs due to prior year charges related to damaged longwall mining equipment; and
- $12 million of higher wheeling revenue, primarily due to increased volumes and short-term prices.

The increases above were partially offset by:

- $99 million of higher purchased electricity costs due to higher volumes;
- $64 million of lower average retail rates, primarily due to product mix;
- $55 million of lower DSM program revenue (offset in operations and maintenance expense), primarily driven by the recently implemented Utah Sustainable Transportation and Energy Plan ("STEP") program; and
- $31 million of higher coal costs due to higher volumes and prices.

Operations and maintenance decreased $52 million, or 5%, for 2017 compared to 2016 primarily due to a decrease in DSM program expense (offset in revenues) of $55 million driven by the establishment of the Utah STEP program and lower pension expense due to a current year plan change. These decreases were partially offset by higher injury and damage expenses, primarily due to prior year accrual for insurance proceeds and current year settlements, and higher labor costs for storm damage restoration.

Depreciation and amortization increased $26 million, or 3%, for 2017 compared to 2016 primarily due to higher plant-in-service.

Taxes, other than income taxes increased $7 million, or 4%, for 2017 compared to 2016 primarily due to higher assessed property values.

Allowance for borrowed and equity funds decreased $11 million, or 26%, for 2017 compared to 2016 primarily due to a true-up of AFUDC rates.

Income tax expense increased $20 million, or 6%, for 2017 compared to 2016 and the effective tax rate was 32% and 31% for 2017 and 2016, respectively. The effective tax rate increased primarily due to lower production tax credits associated with PacifiCorp's wind-powered generating facilities as a result of the expiration of the 10-year production tax credit periods for certain wind-powered generating facilities, of which 243 MW and 100 MW of net owned capacity expired in 2017 and 2016, respectively.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Gross margin increased $86 million, or 3%, for 2016 compared to 2015 primarily due to:

- $71 million of lower purchased electricity costs primarily due to lower average market prices;
- $57 million of higher retail revenues primarily due to higher retail rates;
- $37 million of lower coal costs primarily due to decreased generation of $95 million, partially offset by higher average unit costs of $31 million and charges related to damaged longwall mining equipment of $20 million; and
- $22 million of lower natural gas costs due to lower market prices, partially offset by increased generation.

The increases above were partially offset by:

- $90 million of lower wholesale electricity revenue due to lower volumes and prices.

Operations and maintenance decreased $18 million, or 2%, for 2016 compared to 2015 primarily due to lower plant maintenance costs associated with reduced generation and lower labor and benefit costs due to lower headcount, partially offset by a Washington rate case decision disallowing returns on recent selective catalytic reduction projects.

Depreciation and amortization increased $13 million, or 2%, for 2016 compared to 2015 primarily due to higher plant in-service.

Taxes, other than income taxes increased $5 million, or 3%, for 2016 compared to 2015 due to higher property taxes primarily from higher assessed property values.

Allowance for borrowed and equity funds decreased $9 million, or 18%, for 2016 compared to 2015 primarily due to lower qualified construction work-in-progress balances.

Income tax expense increased $12 million, or 4%, for 2016 compared to 2015 and the effective tax rate was 31% and 32% for 2016 and 2015, respectively. The decrease in the effective tax rate is due to higher production tax credits associated with PacifiCorp's wind-powered generating facilities.

Liquidity and Capital Resources

As of December 31, 2017, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$	14
Credit facilities[1]		1,000
Less:		
Short-term debt		(80)
Tax-exempt bond support		(130)
Net credit facilities		790
Total net liquidity	$	804
Credit facilities:		
Maturity dates		2020

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

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2017 and 2016 were $1.6 billion and $1.6 billion, respectively. Positive variance from a prior year payment for USA Power litigation, higher receipts from wholesale and retail customers and lower fuel payments, offset by current year higher cash payments for purchased power, income taxes and pension contributions.

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $1.6 billion and $1.7 billion, respectively. The change was primarily due to higher cash paid for income taxes, payment for USA Power litigation and lower receipts from wholesale electricity sales, partially offset by lower purchased electricity payments, lower fuel payments, higher receipts from retail customers and lower cash collateral posted for derivative contracts.

PacifiCorp's income tax cash flows benefited in 2017, 2016, and 2015 from 50% bonus depreciation on qualifying assets placed in service and from production tax credits earned on qualifying projects. In December 2017, the 2017 Tax Reform was enacted which, among other items, reduces the federal corporate tax rate from 35% to 21% effective January 1, 2018 and eliminates bonus depreciation on qualifying regulated utility assets acquired after September 27, 2017, but did not impact production tax credits. PacifiCorp will be proposing to reduce customer rates for a portion of the lower annual income tax expense resulting from the decrease in federal tax rates, and deferring the remainder to offset other costs as approved by the regulatory bodies. PacifiCorp expects lower revenue and income taxes as well as lower bonus depreciation benefits as a result of the 2017 Tax Reform and related regulatory treatment. PacifiCorp does not expect the 2017 Tax Reform and related regulatory treatment to have a material adverse impact on its cash flows, subject to actual regulatory outcomes. Refer to Regulatory Matters in Item 1 of this Form 10-K for further discussion of regulatory matters associated with the 2017 Tax Reform. The timing of PacifiCorp's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2017 and 2016 were $(729) million and $(869) million, respectively. The change mainly reflects a current year decrease in capital expenditures of $134 million.

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(869) million and $(918) million, respectively. The change primarily reflects, a current year net distribution from an affiliate of $26 million, a prior year service territory acquisition of $23 million, and a decrease in capital expenditures of $13 million, partially offset by a prior year equipment sale to an affiliate of $13 million.

Financing Activities

Short-term Debt and Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2017, PacifiCorp had $80 million of short-term debt outstanding at a weighted average interest rate of 1.83%, and as of December 31, 2016, had $270 million of short-term debt outstanding at a weighted average interest rate of 0.96%. For further discussion, refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement with the SEC to issue up to $1.325 billion additional first mortgage bonds through January 2019.

PacifiCorp made repayments on long-term debt, excluding repayments for lease obligations, totaling $52 million and $66 million during the years ended December 31, 2017 and 2016, respectively.

As of December 31, 2017, PacifiCorp had $216 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $213 million plus interest. These letters of credit were fully available as of December 31, 2017 and expire periodically through March 2019.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2017, PacifiCorp estimated it would be able to issue up to $10.1 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

Preferred Stock

As of December 31, 2017 and 2016, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In February 2018, PacifiCorp declared a dividend of $250 million payable to PPW Holdings LLC in March 2018.

In 2017 and 2016, PacifiCorp declared and paid dividends of $600 million and $875 million, respectively, to PPW Holdings LLC.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with an objective of retaining strong investment grade credit ratings, which is expected to facilitate continuing access to flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, customers and creditors and provide a competitive cost of capital and predictable capital market access.

Under existing or prospective authoritative accounting guidance, such as guidance pertaining to consolidations and leases, it is possible that new purchase power and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as capital lease obligations or debt on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments or waivers under financing agreements and from regulators, delay or reduce dividends or spending programs, seek additional new equity contributions from its indirect parent company, BHE, or take other actions.

Future Uses of Cash

PacifiCorp has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

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

	Historical			**Forecast**		
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Transmission system investment	$ 137	$ 94	$ 115	$ 135	$ 305	$ 438
Environmental	114	58	27	19	16	21
Wind investment	—	110	11	547	974	741
Operating and other	665	641	616	511	805	602
Total	$ 916	$ 903	$ 769	$ 1,212	$ 2,100	$ 1,802

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

- Transmission system investment primarily reflects main grid reinforcement costs and costs for the 140-mile 500 kV Aeolus-Bridger/Anticline transmission line, a major segment of PacifiCorp's Energy Gateway Transmission Expansion Program expected to be placed in-service in 2020. Planned spending for the Aeolus-Bridger/Anticline line totals $40 million in 2018, $220 million in 2019 and $346 million in 2020.

- Environmental includes the installation of new or the replacement of existing emissions control equipment at certain generating facilities, including installation or upgrade of selective catalytic reduction control systems and low nitrogen oxide burners to reduce nitrogen oxides, mercury emissions control systems, as well as expenditures for the management of coal combustion residuals and effluent limitation.

- 2016 and 2017 wind investment includes costs for new wind plant construction projects and repowering of certain existing wind plants. The repowering projects entail the replacement of significant components of older turbines. Planned spending for the repowering totals $347 million in 2018, $553 million in 2019 and $153 million in 2020 and for the new wind-powered generating facilities totals $200 million in 2018, $421 million in 2019 and $588 million in 2020, plus approximately $300 million for an assumed vendor supplied financing transaction to be paid in 2020 that is not included in the table above. The repowering projects are expected to be placed in-service at various dates in 2019 and 2020. The new wind-powered generating facilities are also expected to be placed in-service in 2020. The energy production from the repowered and new wind-powered generating facilities is expected to qualify for 100% of the federal renewable electricity production tax credit available for 10 years once the equipment is placed in-service.

- Remaining investments relate to operating projects that consist of routine expenditures for generation, transmission, distribution and other infrastructure needed to serve existing and expected demand, including upgrades to customer meters in Oregon, California, Utah, and Idaho.

Obligations and Commitments

Contractual Obligations

PacifiCorp has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes PacifiCorp's material contractual cash obligations as of December 31, 2017 (in millions):

	Payments Due By Periods				
	2018	**2019-2020**	**2021-2022**	**2023 and Thereafter**	**Total**
Long-term debt, including interest:					
Fixed-rate obligations	$ 855	$ 974	$ 1,609	$ 8,006	$ 11,444
Variable-rate obligations(1)	91	47	8	226	372
Short-term debt, including interest	80	—	—	—	80
Capital leases, including interest	4	7	8	18	37
Operating leases and easements	7	14	13	97	131
Asset retirement obligations	25	31	40	335	431
Power purchase agreements - commercially operable(2):					
Electricity commodity contracts	231	242	223	871	1,567
Electricity capacity contracts	37	70	60	655	822
Electricity mixed contracts	8	14	12	48	82
Power purchase agreements - non-commercially operable(2)	9	44	53	451	557
Transmission	112	162	88	428	790
Fuel purchase agreements(2):					
Natural gas supply and transportation	40	56	53	233	382
Coal supply and transportation	655	1,154	737	1,035	3,581
Other purchase obligations	121	88	39	80	328
Other long-term liabilities(3)	15	18	13	65	111
Total contractual cash obligations	$ 2,290	$ 2,921	$ 2,956	$ 12,548	$ 20,715

(1) Consists of principal and interest for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are assumed to equal December 31, 2017 rates. Refer to "Interest Rate Risk" in Item 7A of this Form 10-K for additional discussion related to variable-rate liabilities.

(2) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to energy output, generally of a specified generating facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments. PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

(3) Includes environmental and hydroelectric relicensing commitments recorded in the Consolidated Balance Sheets that are contractually or legally binding. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are excluded since cash payments are based primarily on taxable income for each year. Uncertain tax positions are also excluded because the amounts and timing of cash payments are not certain.

Regulatory Matters

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

Environmental Laws and Regulations

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

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

Collateral and Contingent Features

Debt and preferred securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2017, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the three recognized credit rating agencies were investment grade.

PacifiCorp has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2017, PacifiCorp would have been required to post $233 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

Limitations

In addition to PacifiCorp's capital structure objectives, its debt capacity is also governed by its contractual and regulatory commitments.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0 as of the last day of each fiscal quarter. Management believes that PacifiCorp could have borrowed an additional $6.9 billion as of December 31, 2017 without exceeding this threshold. Any additional borrowings would be subject to market conditions, and amounts may be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements.

The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2017, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by BHE as common equity. As of December 31, 2017, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 54%, and management believes that PacifiCorp could have declared a dividend of $2.5 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or BHE if PacifiCorp's senior unsecured debt is rated BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2017, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

Inflation

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

Off-Balance Sheet Arrangements

PacifiCorp from time to time enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantees or similar arrangements. PacifiCorp currently has indemnification obligations in connection with the sale of certain assets. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with authoritative accounting guidance. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. Refer to Notes 10 and 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for more information on these obligations and arrangements.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit PacifiCorp's ability to recover its costs. PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $1.061 billion and total regulatory liabilities were $3.071 billion as of December 31, 2017. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and liabilities.

Derivatives

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage its commodity price and, at times, interest rate risk. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices and interest rates. As of December 31, 2017, PacifiCorp had no derivative contracts outstanding related to interest rate risk. Refer to Notes 11 and 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by accounting principles generally accepted in the United States of America. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. As of December 31, 2017, PacifiCorp had a net derivative liability of $104 million related to contracts valued using either quoted prices or forward price curves based upon observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are critical because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2017, PacifiCorp had a net derivative asset of $- million related to contracts where PacifiCorp uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

PacifiCorp's derivative contracts are probable of inclusion in rates and changes in the estimated fair value of derivative contracts are generally recorded as regulatory assets. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2017, PacifiCorp had $101 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. In addition, PacifiCorp contributes to a joint trustee pension plan for benefits offered to certain bargaining units. PacifiCorp recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2017, PacifiCorp recognized a net liability totaling $139 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2017, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets and accumulated other comprehensive loss totaled $407 million and $20 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rate and expected long-term rate of return on plan assets. These key assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2017.

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

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

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and the funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plan	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2017 Benefit Obligations:				
Discount rate	$ (65)	$ 71	$ (14)	$ 16
Effect on 2017 Periodic Cost:				
Discount rate	$ —	$ (1)	$ 1	$ —
Expected rate of return on plan assets	(5)	5	(1)	1

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

Income Taxes

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

It is probable that PacifiCorp will pass income tax benefits and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to its customers. As of December 31, 2017, these amounts were recognized as a net regulatory liability of $1.96 billion and will be included in rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $255 million as of December 31, 2017. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which PacifiCorp transacts. The following discussion addresses the significant market risks associated with PacifiCorp's business activities. PacifiCorp has established guidelines for credit risk management. Refer to Notes 2 and 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's contracts accounted for as derivatives.

Risk Management

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee recommends, and executive management establishes, policies, limits and approved products, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in PacifiCorp's business. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management and management information systems required to effectively monitor such transactions. PacifiCorp's risk management policy provides for the use of only those contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions.

Commodity Price Risk

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

PacifiCorp measures the market risk in its electricity and natural gas portfolio daily, utilizing a historical Value-at-Risk ("VaR") approach and other measurements of net position. PacifiCorp also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period. VaR computations for the electricity and natural gas commodity portfolio are based on a historical simulation technique, utilizing historical price changes over a specified (holding) period to simulate potential forward energy market price curve movements to estimate the potential unfavorable impact of such price changes on the portfolio positions. The quantification of market risk using VaR provides a consistent measure of risk across PacifiCorp's continually changing portfolio. VaR represents an estimate of possible changes at a given level of confidence in fair value that would be measured on its portfolio assuming hypothetical movements in forward market prices and is not necessarily indicative of actual results that may occur.

PacifiCorp's VaR computations utilize several key assumptions. The calculation includes short-term commodity contracts, the expected resource and demand obligations from PacifiCorp's long-term contracts, the expected generation levels from PacifiCorp's generation assets and the expected retail and wholesale load levels. The portfolio reflects flexibility contained in contracts and assets, which accommodate the normal variability in PacifiCorp's demand obligations and generation availability. These contracts and assets are valued to reflect the variability PacifiCorp experiences as a load-serving entity. Contracts or assets that contain flexible elements are often referred to as having embedded options or option characteristics. These options provide for energy volume changes that are sensitive to market price changes. Therefore, changes in the option values affect the energy position of the portfolio with respect to market prices, and this effect is calculated daily. When measuring portfolio exposure through VaR, these position changes that result from the option sensitivity are held constant through the historical simulation. PacifiCorp's VaR methodology is based on a 36-month forward position, 95% confidence interval and one-day holding period.

As of December 31, 2017, PacifiCorp's estimated potential one-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 36 months was $10 million, as measured by the VaR computations described above. The minimum, average and maximum daily VaR (one-day holding periods) were as follows for the year ended December 31 (in millions):

	2017
Minimum VaR (measured)	$ 6
Average VaR (calculated)	8
Maximum VaR (measured)	14

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2017. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed estimated VaR levels.

Fair Value of Derivatives

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $74 million and $69 million as of December 31, 2017 and 2016, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions):

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2017:			
Total commodity derivative contracts	$ (104)	$ (102)	$ (106)
As of December 31, 2016			
Total commodity derivative contracts	$ (77)	$ (59)	$ (95)

PacifiCorp's commodity derivative contracts are generally recoverable from customers in rates; therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose PacifiCorp to earnings volatility. As of December 31, 2017 and 2016, a regulatory asset of $101 million and $73 million, respectively, was recorded related to the net derivative liability of $104 million and $77 million, respectively. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher or the level of wholesale electricity sales are lower than what is included in rates, including the impacts of adjustment mechanisms.

Interest Rate Risk

PacifiCorp is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed-rate long-term debt does not expose PacifiCorp to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. The nature and amount of PacifiCorp's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6, 7 and 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2017 and 2016, PacifiCorp had short- and long-term variable-rate obligations totaling $442 million and $662 million, respectively that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2017 is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2017 and 2016.

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2017, PacifiCorp's aggregate credit exposure from wholesale activities totaled $127 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2017, $125 million, or 98.5%, 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, 2017, three counterparties comprised $91 million, or 72%, of the aggregate credit exposure. The three 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, 2017.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2018

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14	$ 17
Accounts receivable, net	684	728
Income taxes receivable	59	17
Inventories	433	443
Regulatory assets	31	53
Prepaid Expenses	73	64
Other current assets	21	32
Total current assets	1,315	1,354
Property, plant and equipment, net	19,203	19,162
Regulatory assets	1,030	1,490
Other assets	372	388
Total assets	$ 21,920	$ 22,394

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

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

	As of December 31,	
	2017	**2016**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 453	$ 408
Accrued employee expenses	70	67
Accrued interest	115	115
Accrued property and other taxes	66	63
Short-term debt	80	270
Current portion of long-term debt and capital lease obligations	588	58
Regulatory liabilities	75	54
Other current liabilities	170	164
Total current liabilities	1,617	1,199
Long-term debt and capital lease obligations	6,437	7,021
Regulatory liabilities	2,996	978
Deferred income taxes	2,582	4,880
Other long-term liabilities	733	926
Total liabilities	14,365	15,004
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock	2	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	3,089	2,921
Accumulated other comprehensive loss, net	(15)	(12)
Total shareholders' equity	7,555	7,390
Total liabilities and shareholders' equity	$ 21,920	$ 22,394

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Operating revenue	$ 5,237	$ 5,201	$ 5,232
Operating costs and expenses:			
Energy costs	1,770	1,751	1,868
Operations and maintenance	1,012	1,064	1,082
Depreciation and amortization	796	770	757
Taxes, other than income taxes	197	190	185
Total operating costs and expenses	3,775	3,775	3,892
Operating income	1,462	1,426	1,340
Other income (expense):			
Interest expense	(381)	(380)	(379)
Allowance for borrowed funds	11	15	18
Allowance for equity funds	20	27	33
Other, net	16	15	11
Total other income (expense)	(334)	(323)	(317)
Income before income tax expense	1,128	1,103	1,023
Income tax expense	360	340	328
Net income	$ 768	$ 763	$ 695

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

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

	Years Ended December 31,		
	2017	2016	2015
Net income	$ 768	$ 763	$ 695
Other comprehensive (loss) income, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $3, $- and $1	(3)	(1)	2
Comprehensive income	$ 765	$ 762	$ 697

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

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

	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholders' Equity
Balance, December 31, 2014	$ 2	$ —	$ 4,479	$ 3,288	$ (13)	$ 7,756
Net income	—	—	—	695	—	695
Other comprehensive income	—	—	—	—	2	2
Common stock dividends declared	—	—	—	(950)	—	(950)
Balance, December 31, 2015	2	—	4,479	3,033	(11)	7,503
Net income	—	—	—	763	—	763
Other comprehensive loss	—	—	—	—	(1)	(1)
Common stock dividends declared	—	—	—	(875)	—	(875)
Balance, December 31, 2016	2	—	4,479	2,921	(12)	7,390
Net income	—	—	—	768	—	768
Other comprehensive loss	—	—	—	—	(3)	(3)
Common stock dividends declared	—	—	—	(600)	—	(600)
Balance, December 31, 2017	$ 2	$ —	$ 4,479	$ 3,089	$ (15)	$ 7,555

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 768	$ 763	$ 695
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	796	770	757
Allowance for equity funds	(20)	(27)	(33)
Deferred income taxes and amortization of investment tax credits	70	139	172
Changes in regulatory assets and liabilities	18	122	63
Other, net	9	4	6
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	48	(20)	6
Derivative collateral, net	(6)	6	(47)
Inventories	10	(21)	(7)
Prepaid expenses	(8)	(5)	(1)
Income taxes	(49)	—	116
Accounts payable and other liabilities	(61)	(163)	7
Net cash flows from operating activities	1,575	1,568	1,734
Cash flows from investing activities:			
Capital expenditures	(769)	(903)	(916)
Other, net	40	34	(2)
Net cash flows from investing activities	(729)	(869)	(918)
Cash flows from financing activities:			
Proceeds from long-term debt	—	—	248
Repayments of long-term debt and capital lease obligations	(58)	(68)	(124)
Net (repayments) proceeds from short-term debt	(190)	250	—
Common stock dividends	(600)	(875)	(950)
Other, net	(1)	(1)	(1)
Net cash flows from financing activities	(849)	(694)	(827)
Net change in cash and cash equivalents	(3)	5	(11)
Cash and cash equivalents at beginning of period	17	12	23
Cash and cash equivalents at end of period	$ 14	$ 17	$ 12

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

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining services. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit PacifiCorp's ability to recover its costs. PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2017 and 2016, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

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

Allowance for Doubtful Accounts

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

	2017	**2016**	**2015**
Beginning balance	$ 7	$ 7	$ 7
Charged to operating costs and expenses, net	15	12	10
Write-offs, net	(12)	(12)	(10)
Ending balance	$ 10	$ 7	$ 7

Derivatives

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

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or energy costs on the Consolidated Statements of Operations.

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

Inventories

Inventories consist mainly of materials and supplies totaling $235 million and $228 million as of December 31, 2017, and 2016, respectively, and fuel stocks, totaling $198 million and $215 million as of December 31, 2017, and 2016, respectively. Inventories are stated at the lower of average cost or net realizable value.

Property, Plant and Equipment, Net

General

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

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

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

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of property, plant and equipment, is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

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.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2017 and 2016, unbilled revenue was $255 million and $275 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates charged are established by regulators or contractual arrangements.

The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. The estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes.

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

Income Taxes

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

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law which, among other items, reduces the federal corporate tax rate from 35% to 21%. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability 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. Investment tax credits are included in other long-term liabilities on the Consolidated Balance Sheets and were $16 million and $18 million as of December 31, 2017 and 2016, respectively.

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

Segment Information

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

New Accounting Pronouncements

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, which amends FASB Accounting Standards Codification ("ASC") Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. This guidance must be adopted retrospectively for the presentation of the service cost component and the other components of net benefit cost in the statement of operations and prospectively for the capitalization of the service cost component in the balance sheet. PacifiCorp adopted this guidance on January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp adopted this guidance on January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp adopted this guidance January 1, 2018 and the adoption of this guidance will not have a material impact on the Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. PacifiCorp plans to adopt this guidance effective January 1, 2019 and is currently evaluating the impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In January 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. PacifiCorp adopted this guidance on January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. During 2016 and 2017, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. PacifiCorp adopted this guidance on January 1, 2018 under the modified retrospective method and the adoption will not have an impact on its Consolidated Financial Statements but will increase the disclosures included within Notes to Consolidated Financial Statements. The timing and amount of revenue recognized after adoption of the new guidance will not be different than before as a majority of revenue is recognized when PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date. PacifiCorp plans to quantitatively disaggregate revenue in the required financial statement footnote by customer class.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2017	2016
Utility Plant:			
Generation	14 - 67 years	$ 12,490	$ 12,371
Transmission	58 - 75 years	6,226	6,055
Distribution	20 - 70 years	6,792	6,590
Intangible plant[(1)]	5 - 62 years	937	884
Other	5 - 60 years	1,435	1,384
Utility plant in service		27,880	27,284
Accumulated depreciation and amortization		(9,366)	(8,790)
Utility plant in service, net		18,514	18,494
Other non-regulated, net of accumulated depreciation and amortization	45 years	11	11
Plant, net		18,525	18,505
Construction work-in-progress		678	657
Property, plant and equipment, net		$ 19,203	$ 19,162

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

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 2.9% for the years ended December 31, 2017, 2016 and 2015, respectively.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of $156 million as of December 31, 2017 and 2016, respectively, and accumulated depreciation of $122 million and $117 million as of December 31, 2017 and 2016, respectively.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2017 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,442	$ 616	$ 12
Hunter No. 1	94	474	172	7
Hunter No. 2	60	297	106	1
Wyodak	80	469	216	1
Colstrip Nos. 3 and 4	10	247	131	4
Hermiston	50	180	81	1
Craig Nos. 1 and 2	19	365	231	3
Hayden No. 1	25	74	34	—
Hayden No. 2	13	43	21	—
Foote Creek	79	40	26	—
Transmission and distribution facilities	Various	794	238	67
Total		$ 4,425	$ 1,872	$ 96

(5) Regulatory Matters

Regulatory Assets

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

	Weighted Average Remaining Life	2017	2016
Deferred income taxes[1]	N/A	$ —	$ 421
Employee benefit plans[2]	20 years	418	525
Utah mine disposition[3]	Various	156	166
Unamortized contract values	6 years	89	98
Deferred net power costs	1 year	21	33
Unrealized loss on derivative contracts	4 years	101	73
Asset retirement obligation	22 years	100	82
Other	Various	176	145
Total regulatory assets		$ 1,061	$ 1,543
Reflected as:			
Current assets		$ 31	$ 53
Noncurrent assets		1,030	1,490
Total regulatory assets		$ 1,061	$ 1,543

(1) Amount primarily represents income tax benefits and expense related to certain property-related basis differences and other various items that were previously passed on 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 rates when recognized.

(3) Amounts represent regulatory assets established as a result of the Utah mine disposition in 2015 for the net property, plant and equipment not considered probable of disallowance and for the portion of losses associated with the assets held for sale, UMWA 1974 Pension Plan withdrawal and closure costs incurred to date considered probable of recovery.

PacifiCorp had regulatory assets not earning a return on investment of $589 million and $1.019 billion as of December 31, 2017 and 2016, respectively.

Regulatory Liabilities

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

	Weighted Average Remaining Life	2017	2016
Cost of removal[1]	26 years	$ 955	$ 917
Deferred income taxes[2]	Various	1,960	9
Other	Various	156	106
Total regulatory liabilities		$ 3,071	$ 1,032
Reflected as:			
Current liabilities		$ 75	$ 54
Noncurrent liabilities		2,996	978
Total regulatory liabilities		$ 3,071	$ 1,032

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

(2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse. See Note 8 for further discussion of 2017 Tax Reform.

Utah Mine Disposition

In December 2014, PacifiCorp filed an advice letter with the California Public Utility Commission ("CPUC") to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC. On February 6, 2017, a joint motion was filed with the CPUC seeking approval of a settlement agreement reached by PacifiCorp and all other parties. The agreement states, among other things, that the decision to sell certain Utah mining assets is in the public interest. Parties also reserve their rights to additional testimony, briefs, and hearings to the extent the CPUC determines that additional California Environmental Quality Act proceedings are necessary. A CPUC decision on the joint motion and settlement agreement is expected in 2018.

(6) Short-term Debt and Other Financing Agreements

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

2017:		
Credit facilities	$	1,000
Less:		
Short-term debt		(80)
Tax-exempt bond support		(130)
Net credit facilities	$	790
2016:		
Credit facilities	$	1,000
Less:		
Short-term debt		(270)
Tax-exempt bond support		(142)
Net credit facilities	$	588

PacifiCorp has a $600 million unsecured credit facility expiring in June 2020 with two one-year extension options subject to lender consent and a $400 million unsecured credit facility expiring in June 2020 with a one-year extension option subject to lender consent. 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 variable interest rates based on the Eurodollar rate or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities.

As of December 31, 2017 and 2016, the weighted average interest rate on commercial paper borrowings outstanding was 1.83% and 0.96%, respectively. These credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2017 and 2016, PacifiCorp had $230 million and $269 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2017 and 2016, $216 million and $255 million, respectively, of these letters of credit, support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2019 and $14 million support certain transactions required by third parties and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(7) Long-term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows as of December 31 (dollars in millions):

	2017			2016	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
2.95% to 8.53%, due 2018 to 2022	$ 1,875	$ 1,872	4.80%	$ 1,872	4.80%
2.95% to 8.23%, due 2023 to 2026	1,224	1,218	4.10	1,217	4.10
7.70% due 2031	300	298	7.70	298	7.70
5.25% to 6.25%, due 2034 to 2037	2,050	2,040	5.90	2,039	5.90
4.10% to 6.35%, due 2038 to 2042	1,250	1,236	5.60	1,235	5.60
Variable-rate series, tax-exempt bond obligations (2017-1.60% to 1.87%; 2016-0.69% to 0.86%):					
Due 2018 to 2020	79	79	1.77	91	0.85
Due 2018 to 2025(1)	70	70	1.81	108	0.74
Due 2024(1)(2)	143	142	1.73	142	0.70
Due 2024 to 2025(2)	50	50	1.72	50	0.80
Total long-term debt	7,041	7,005		7,052	
Capital lease obligations:					
8.75% to 14.61%, due through 2035	20	20	11.46	27	11.09
Total long-term debt and capital lease obligations	$ 7,061	$ 7,025		$ 7,079	

Reflected as:

	2017	2016
Current portion of long-term debt and capital lease obligations	$ 588	$ 58
Long-term debt and capital lease obligations	6,437	7,021
Total long-term debt and capital lease obligations	$ 7,025	$ 7,079

1) Supported by $216 million and $255 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2017 and 2016, respectively.

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

PacifiCorp's long-term debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds in whole or in part at any time through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission to issue up to $1.325 billion additional first mortgage bonds through January 2019.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $27 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2017.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, a power purchase agreement and real estate. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to two of PacifiCorp's generating facilities. Net capital lease assets of $20 million and $27 million as of December 31, 2017 and 2016, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2017, the annual principal maturities of long-term debt and total capital lease obligations for 2018 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2018	$ 586	$ 4	$ 590
2019	350	4	354
2020	38	3	41
2021	420	6	426
2022	605	2	607
Thereafter	5,042	18	5,060
Total	7,041	37	7,078
Unamortized discount and debt issuance costs	(36)	—	(36)
Amounts representing interest	—	(17)	(17)
Total	$ 7,005	$ 20	$ 7,025

(8) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018 and limitations on bonus depreciation for utility property. GAAP requires the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, PacifiCorp reduced deferred income tax liabilities $2,361 million. As it is probable the change in deferred taxes will be passed back to customers through regulatory mechanisms, PacifiCorp increased net regulatory liabilities by $2,358 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. PacifiCorp has recorded the impacts of the 2017 Tax Reform and believes all the impacts to be complete with the exception of interpretations of the bonus depreciation rules. PacifiCorp has determined the amounts recorded and the interpretations relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. PacifiCorp believes its interpretations for bonus depreciation to be reasonable, however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

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

	2017	2016	2015
Current:			
Federal	$ 249	$ 169	$ 130
State	41	32	26
Total	290	201	156
Deferred:			
Federal	59	123	148
State	15	21	29
Total	74	144	177
Investment tax credits	(4)	(5)	(5)
Total income tax expense	$ 360	$ 340	$ 328

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:

	2017	2016	2015
Federal statutory income tax rate	35%	35%	35%
State income taxes, net of federal income tax benefit	3	3	3
Federal income tax credits	(5)	(6)	(6)
Other	(1)	(1)	—
Effective income tax rate	32%	31%	32%

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

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

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 756	$ 393
Employee benefits	84	202
Derivative contracts and unamortized contract values	48	67
State carryforwards	83	69
Asset retirement obligations	50	78
Other	50	94
	1,071	903
Deferred income tax liabilities:		
Property, plant and equipment	(3,381)	(5,161)
Regulatory assets	(261)	(586)
Other	(11)	(36)
	(3,653)	(5,783)
Net deferred income tax liability	$ (2,582)	$ (4,880)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2017 (in millions):

	State
Net operating loss carryforwards	$ 1,356
Deferred income taxes on net operating loss carryforwards	$ 63
Expiration dates	2018 - 2032
Tax credit carryforwards	$ 20
Expiration dates	2018 - indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2009. The statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2009, with the exception of California and Utah, for which the statute of limitations have expired through March 31, 2006. The statute of limitations expiring for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the examination is not closed.

As of December 31, 2017 and 2016, PacifiCorp had unrecognized tax benefits totaling $10 million and $12 million, respectively, related to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective income tax rate.

(9) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary previously contributed to a multiemployer pension plan for benefits offered to certain bargaining units.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include non-contributory defined benefit pension plans, collectively the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to all non-union employees hired after January 1, 2008. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011 as they are now being provided with enhanced 401(k) Plan benefits. However, certain limited union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula. The SERP was closed to new participants as of March 21, 2006 and froze future accruals for active participants as of December 31, 2014.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits 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		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
Service cost	$ —	$ 4	$ 4	$ 2	$ 2	$ 3
Interest cost	49	54	53	14	15	16
Expected return on plan assets	(72)	(75)	(77)	(21)	(21)	(23)
Net amortization	14	34	42	(6)	(5)	(4)
Net periodic benefit cost (credit)	$ (9)	$ 17	$ 22	$ (11)	$ (9)	$ (8)

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	
	2017	**2016**	**2017**	**2016**
Plan assets at fair value, beginning of year	$ 999	$ 1,043	$ 302	$ 305
Employer contributions	54	5	1	1
Participant contributions	—	—	7	6
Actual return on plan assets	166	51	49	17
Benefits paid	(108)	(100)	(27)	(27)
Plan assets at fair value, end of year	$ 1,111	$ 999	$ 332	$ 302

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

	Pension		Other Postretirement	
	2017	**2016**	**2017**	**2016**
Benefit obligation, beginning of year	$ 1,276	$ 1,289	$ 358	$ 362
Service cost	—	4	2	2
Interest cost	49	54	14	15
Participant contributions	—	—	7	6
Actuarial (gain) loss	34	29	(23)	—
Benefits paid	(108)	(100)	(27)	(27)
Benefit obligation, end of year	$ 1,251	$ 1,276	$ 331	$ 358
Accumulated benefit obligation, end of year	$ 1,251	$ 1,276		

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	
	2017	2016	2017	2016
Plan assets at fair value, end of year	$ 1,111	$ 999	$ 332	$ 302
Less - Benefit obligation, end of year	1,251	1,276	331	358
Funded status	$ (140)	$ (277)	$ 1	$ (56)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 5	$ —	$ 1	$ —
Other current liabilities	(4)	(5)	—	—
Other long-term liabilities	(141)	(272)	—	(56)
Amounts recognized	$ (140)	$ (277)	$ 1	$ (56)

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $60 million and $55 million as of December 31, 2017 and 2016, respectively. These assets are not included in the plan assets in the above table, but are reflected in cash and cash equivalents, totaling $9 million and $- million as of December 31, 2017 and 2016, respectively, and noncurrent other assets, totaling $51 million and 55 million as of December 31, 2017 and 2016, respectively, on the Consolidated Balance Sheets.

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2017	2016	2017	2016
Net loss (gain)	$ 442	$ 518	$ (12)	$ 39
Prior service credit	—	—	(6)	(13)
Regulatory deferrals	(4)	(7)	7	8
Total	$ 438	$ 511	$ (11)	$ 34

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2017 and 2016 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2015	$ 473	$ 19	$ 492
Net loss arising during the year	51	2	53
Net amortization	(33)	(1)	(34)
Total	18	1	19
Balance, December 31, 2016	491	20	511
Net (gain) loss arising during the year	(60)	1	(59)
Net amortization	(13)	(1)	(14)
Total	(73)	—	(73)
Balance, December 31, 2017	$ 418	$ 20	$ 438

Other Postretirement	Regulatory Asset (Liability)
Balance, December 31, 2015	$ 26
Net loss arising during the year	3
Net amortization	5
Total	8
Balance, December 31, 2016	34
Net gain arising during the year	(51)
Net amortization	6
Total	(45)
Balance, December 31, 2017	$ (11)

The net loss, prior service credit and regulatory deferrals that will be amortized in 2018 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 16	$ —	$ (2)	$ 14
Other postretirement	—	(6)	1	(5)
Total	$ 16	$ (6)	$ (1)	$ 9

Plan Assumptions

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

	Pension			Other Postretirement		
	2017	2016	2015	2017	2016	2015
Benefit obligations as of December 31:						
Discount rate	3.60%	4.05%	4.40%	3.60%	4.05%	4.35%
Rate of compensation increase	N/A	N/A	2.75	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.05%	4.40%	4.00%	4.05%	4.35%	3.99%
Expected return on plan assets	7.25	7.50	7.50	7.25	7.50	7.08
Rate of compensation increase	N/A	2.75	2.75	N/A	N/A	N/A

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

As a result of a plan amendment effective on January 1, 2017, the benefit obligation for the Retirement Plan is no longer affected by future increases in compensation. As a result of a labor settlement reached with UMWA in December 2014, the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2018. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding of its other postretirement benefit plan is subject to tax deductibility and subordination limits and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2018 through 2022 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2018	$ 108	$ 25
2019	107	25
2020	103	26
2021	99	23
2022	94	23
2023-2027	393	100

Plan Assets

Investment Policy and Asset Allocations

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

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2017:

	Pension(1)	**Other Postretirement**(1)
	%	%
Debt securities(2)	33 - 38	33 - 37
Equity securities(2)	49 - 60	61 - 65
Limited partnership interests	7 - 12	1 - 3
Other	0 - 1	0 - 1

(1) PacifiCorp's Retirement Plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plan are held in Voluntary Employees' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the VEBA trusts.

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

Fair Value Measurements

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

	Input Levels for Fair Value Measurements			
	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As of December 31, 2017:				
Cash equivalents	$ —	$ 43	$ —	$ 43
Debt securities:				
United States government obligations	45	—	—	45
Corporate obligations	—	60	—	60
Municipal obligations	—	9	—	9
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	416	—	—	416
International companies	22	—	—	22
Total assets in the fair value hierarchy	$ 483	$ 149	$ —	632
Investment funds[(2)] measured at net asset value				416
Limited partnership interests[(3)] measured at net asset value				63
Investments at fair value				$ 1,111
As of December 31, 2016:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	25	—	—	25
Corporate obligations	—	36	—	36
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	389	—	—	389
International companies	15	—	—	15
Investment funds[(2)]	83	—	—	83
Total assets in the fair value hierarchy	$ 512	$ 89	$ —	601
Investment funds[(2)] measured at net asset value				337
Limited partnership interests[(3)] measured at net asset value				61
Investments at fair value				$ 999

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

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 60% and 40% respectively, for 2017 and 54% and 46%, respectively, for 2016, and are invested in United States and international securities of approximately 57% and 43%, respectively, for 2017 and 39% and 61%, respectively, for 2016.

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

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

	Input Levels for Fair Value Measurements			
	Level 1[1]	Level 2[1]	Level 3[1]	Total
As of December 31, 2017:				
Cash and cash equivalents	$ 4	$ 3	$ —	$ 7
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	16	—	16
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	16	—	16
Equity securities:				
United States companies	98	—	—	98
International companies	6	—	—	6
Investment funds[2]	32	—	—	32
Total assets in the fair value hierarchy	$ 151	$ 37	$ —	188
Investment funds[2] measured at net asset value				140
Limited partnership interests[3] measured at net asset value				4
Investments at fair value				$ 332
As of December 31, 2016:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	13	—	13
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	13	—	13
Equity securities:				
United States companies	93	—	—	93
International companies	4	—	—	4
Investment funds[2]	32	—	—	32
Total assets in the fair value hierarchy	$ 144	$ 29	$ —	173
Investment funds[2] measured at net asset value				125
Limited partnership interests[3] measured at net asset value				4
Investments at fair value				$ 302

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

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 63% and 37%, respectively, for 2017 and 62% and 38%, respectively, for 2016, and are invested in United States and international securities of approximately 77% and 23%, respectively, for 2017 and 71% and 29%, respectively, for 2016.

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

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and its subsidiary, Energy West Mining Company, previously contributed to the UMWA 1974 Pension Plan (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMWA labor settlement, PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp recorded its estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. PacifiCorp has subsequently revised its estimate due to changes in facts and circumstances for a withdrawal occurring by July 2015. As communicated in a letter received in August 2016, the plan trustees have determined a withdrawal liability of $115 million. Energy West Mining Company began making installment payments in November 2016 and has the option to elect a lump sum payment to settle the withdrawal obligation. The ultimate amount paid by Energy West Mining Company to settle the obligation is dependent on a variety of factors, including the results of ongoing negotiations with the plan trustees.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this plan.

The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert back to employers. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan. This occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension Plan. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that withdrew during the three years prior to a mass withdrawal.

The following table presents PacifiCorp's and Energy West Mining Company's participation in individually significant joint trustee and multiemployer pension plans for the years ended December 31 (dollars in millions):

		PPA zone status or plan funded status percentage for plan years beginning July 1,					Contributions[1]			
Plan name	**Employer Identification Number**	**2017**	**2016**	**2015**	**Funding improvement plan**	**Surcharge imposed under PPA[1]**	**2017**	**2016**	**2015**	**Year contributions to plan exceeded more than 5% of total contributions[2]**
UMWA 1974 Pension Plan	52-1050282	Critical and Declining	Critical and Declining	Critical and Declining	Implemented	Yes	$ —	$ —	$ 1	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 7	$ 8	$ 8	2015, 2014, 2013

(1) PacifiCorp's and Energy West Mining Company's minimum contributions to the plans are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements and the number of mining hours worked for the UMWA 1974 Pension Plan, respectively, subject to ERISA minimum funding requirements. As a result of the plan's critical status, Energy West Mining Company was required to begin paying a surcharge for hours worked on and after December 1, 2014.

(2) For the UMWA 1974 Pension Plan, information is for plan years beginning July 1, 2015, 2014 and 2013. Information for the plan year beginning July 1, 2016 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2015, 2014 and 2013. Information for the plan year beginning July 1, 2016 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in 2020.

Defined Contribution Plan

PacifiCorp's 401(k) plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution and, as of January 1, 2017, all participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) plan were \$39 million, \$34 million and \$35 million for the years ended December 31, 2017, 2016 and 2015, respectively.

(10) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. Cost of removal regulatory liabilities totaled \$955 million and \$917 million as of December 31, 2017 and 2016, respectively.

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

	2017	2016
Beginning balance	$ 215	$ 224
Change in estimated costs	(8)	2
Additions	6	—
Retirements	(6)	(19)
Accretion	8	8
Ending balance	$ 215	$ 215
Reflected as:		
Other current liabilities	$ 25	$ 21
Other long-term liabilities	190	194
	$ 215	$ 215

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(11) Risk Management and Hedging Activities

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

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

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 12 for additional information on derivative contracts.

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

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2017:					
Not designated as hedging contracts(1):					
Commodity assets	$ 11	$ 1	$ 1	$ —	$ 13
Commodity liabilities	(3)	—	(32)	(82)	(117)
Total	8	1	(31)	(82)	(104)
Total derivatives	8	1	(31)	(82)	(104)
Cash collateral receivable	—	—	17	57	74
Total derivatives - net basis	$ 8	$ 1	$ (14)	$ (25)	$ (30)
As of December 31, 2016:					
Not designated as hedging contracts(1):					
Commodity assets	$ 24	$ 2	$ 1	$ —	$ 27
Commodity liabilities	(6)	—	(14)	(84)	(104)
Total	18	2	(13)	(84)	(77)
Total derivatives	18	2	(13)	(84)	(77)
Cash collateral receivable	—	—	10	59	69
Total derivatives - net basis	$ 18	$ 2	$ (3)	$ (25)	$ (8)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2017 and 2016, a regulatory asset of $101 million and $73 million, respectively, was recorded related to the net derivative liability of $104 million and $77 million, respectively.

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

	2017	2016	2015
Beginning balance	$ 73	$ 133	$ 85
Changes in fair value recognized in regulatory assets	47	(27)	82
Net gains reclassified to operating revenue	9	10	40
Net losses reclassified to energy costs	(28)	(43)	(74)
Ending balance	$ 101	$ 73	$ 133

Derivative Contract Volumes

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

	Unit of Measure	2017	2016
Electricity (sales)	Megawatt hours	(9)	(3)
Natural gas purchases	Decatherms	113	84
Fuel oil purchases	Gallons	—	11

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $110 million and $97 million as of December 31, 2017 and 2016, respectively, for which PacifiCorp had posted collateral of $74 million and $69 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, 2017 and 2016, PacifiCorp would have been required to post $34 million and $22 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(12) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.

- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

- Level 3 - Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

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

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other[1]**	**Total**
As of December 31, 2017:					
Assets:					
Commodity derivatives	$ —	$ 13	$ —	$ (4)	$ 9
Money market mutual funds[2]	21	—	—	—	21
Investment funds	21	—	—	—	21
	$ 42	$ 13	$ —	$ (4)	$ 51
Liabilities - Commodity derivatives	$ —	$ (117)	$ —	$ 78	$ (39)
As of December 31, 2016:					
Assets:					
Commodity derivatives	$ —	$ 27	$ —	$ (7)	$ 20
Money market mutual funds [2]	13	—	—	—	13
Investment funds	17	—	—	—	17
	$ 30	$ 27	$ —	$ (7)	$ 50
Liabilities - Commodity derivatives	$ —	$ (104)	$ —	$ 76	$ (28)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $74 million and $69 million as of December 31, 2017 and 2016, respectively.

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

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 11 for further discussion regarding PacifiCorp's risk management and hedging activities.

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

PacifiCorp's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of PacifiCorp's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2017		2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,005	$ 8,370	$ 7,052	$ 8,204

(13) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Environmental Laws and Regulations

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

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses with the FERC. In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the state of California, the state of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provided that the United States Department of the Interior would conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's mainstem dams was in the public interest and would advance restoration of the Klamath Basin's salmonid fisheries. If it was determined that dam removal should proceed, dam removal would begin no earlier than 2020.

Congress failed to pass legislation needed to implement the original KHSA. Hence, in February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon and the United States Departments of the Interior and Commerce) executed an agreement in principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. On April 6, 2016, PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce and other stakeholders executed an amendment to the KHSA. Consistent with the terms of the amended KHSA, on September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC"), a private, independent nonprofit 501(c)(3) organization formed by signatories of the amended KSHA, jointly filed an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities from PacifiCorp to the KRRC. Also on September 23, 2016, the KRRC filed an application with the FERC to surrender the license and decommission the facilities. The KRRC's license surrender application included a request for the FERC to refrain from acting on the surrender application until after the transfer of the license to the KRRC is effective.

Under the amended KHSA, PacifiCorp and its customers continue to be protected from uncapped dam removal costs and liabilities. The KRRC must indemnify PacifiCorp from liabilities associated with dam removal. The amended KHSA also limits PacifiCorp's contribution to facilities 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. California voters approved a water bond measure in November 2014 from which the state of California's contribution towards facilities removal costs will be drawn. In accordance with this bond measure, additional funding of up to $250 million for facilities removal costs was included in the California state budget in 2016, with the funding effective for at least five years. If facilities 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 the KRRC or an entity other than PacifiCorp in order for removal to proceed.

If certain conditions in the amended KHSA are not satisfied and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

As of December 31, 2017, PacifiCorp's assets included $55 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019, or December 31, 2022, depending upon the state jurisdiction.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $239 million over the next 10 years related to these licenses.

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2017 are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 276	$ 165	$ 161	$ 150	$ 145	$ 1,574	$ 2,471
Purchased electricity contracts - non-commercially operable	9	18	26	26	27	451	557
Fuel contracts	695	619	591	453	337	1,268	3,963
Construction commitments	85	29	3	—	—	—	117
Transmission	112	96	66	49	39	428	790
Operating leases and easements	7	7	7	7	6	97	131
Maintenance, service and other contracts	36	34	22	25	14	80	211
Total commitments	$ 1,220	$ 968	$ 876	$ 710	$ 568	$ 3,898	$ 8,240

Purchased Electricity Contracts - Commercially Operable

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Included in the purchased electricity payments are any power purchase agreements that meet the definition of a lease. Rent expense related to those power purchase agreements that meet the definition of a lease totaled $14 million for 2017 and 2016 and $13 million for 2015.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs on the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2017, 2016 and 2015 energy sources.

Purchased Electricity Contracts - Non-commercially Operable

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

Fuel Contracts

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

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include costs associated with certain generating plant, transmission, and distribution projects.

Transmission

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

Operating Leases and Easements

PacifiCorp has non-cancelable operating leases primarily for certain operating facilities, office space, land and equipment that expire at various dates through the year ending December 31, 2096. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp also has non-cancelable easements for land on which certain of its assets, primarily wind-powered generating facilities, are located. Rent expense totaled $15 million for the years ended December 31, 2017, 2016 and 2015.

Guarantees

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

(14) Preferred Stock

PacifiCorp has 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of $100 per share. PacifiCorp had 24 thousand shares of Serial Preferred Stock issued and outstanding as of December 31, 2017 and 2016. The outstanding preferred stock series are non-redeemable and have annual dividend rates of 6.00% and 7.00%.

In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

PacifiCorp also has 16 million shares of No Par Serial Preferred Stock and 127 thousand shares of 5% Preferred Stock authorized, but no shares were issued or outstanding as of December 31, 2017 and 2016.

(15) Common Shareholder's Equity

In February 2018, PacifiCorp declared a dividend of $250 million payable to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings") in March 2018.

Through PPW Holdings, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2017, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by BHE as common equity. As of December 31, 2017, PacifiCorp's actual common equity percentage, as calculated under this measure, was 54%, and PacifiCorp would have been permitted to dividend $2.5 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE if PacifiCorp's senior unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2017, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 6.

(16) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of $15 million and $12 million as of December 31, 2017 and 2016, respectively.

(17) Variable-Interest Entities

PacifiCorp holds a two-thirds interest in Bridger Coal Company ("Bridger Coal"), which supplies coal to the Jim Bridger generating facility that is owned two-thirds by PacifiCorp and one-third by PacifiCorp's joint venture partner in Bridger Coal. PacifiCorp purchases two-thirds of the coal produced by Bridger Coal, while the remaining coal is purchased by the joint venture partner. The power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Each joint venture partner is jointly and severally liable for the obligations of Bridger Coal. Bridger Coal's necessary working capital to carry out its mining operations is financed by contributions from PacifiCorp and its joint venture partner. PacifiCorp's equity investment in Bridger Coal was $137 million and $165 million as of December 31, 2017 and 2016, respectively. Refer to Note 18 for information regarding related-party transactions with Bridger Coal.

(18) Related-Party Transactions

PacifiCorp has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to PacifiCorp by BHE and its subsidiaries under this agreement totaled $11 million during the year ended December 31, 2017, and $10 million during each of the years ended 2016 and 2015. Payables associated with these administrative services were $2 million as of December 31, 2017 and 2016, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under this agreement totaled $3 million, $4 million and $7 million during the years ended December 31, 2017, 2016 and 2015, respectively. Receivables associated with these administrative services were $1 million as of December 31, 2017 and 2016, respectively.

PacifiCorp also engages in various transactions with several subsidiaries of BHE in the ordinary course of business. Services provided by these subsidiaries in the ordinary course of business and charged to PacifiCorp primarily relate to wholesale electricity purchases and transmission of electricity, transportation of natural gas and employee relocation services. These expenses totaled $6 million, $7 million and $8 million during the years ended December 31, 2017, 2016 and 2015, respectively. Payables associated with these services were $1 million as of December 31, 2017 and 2016, respectively. Amounts charged by PacifiCorp to subsidiaries of BHE for wholesale electricity sales in the ordinary course of business totaled $1 million, $1 million and $2 million during the years ended December 31, 2017, 2016 and 2015, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company ("BNSF"), an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company. Transportation costs under these contracts were $35 million, $37 million and $39 million during the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, PacifiCorp had $3 million and $1 million, respectively, of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated United States federal income tax return. Federal and state income taxes receivable from BHE were $59 million and $17 million as of December 31, 2017 and 2016, respectively. For the years ended December 31, 2017, 2016 and 2015, cash paid for federal and state income taxes to BHE totaled $340 million, $201 million and $40 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2017, 2016 and 2015, PacifiCorp charged Bridger Coal $2 million, $2 million and $19 million, respectively, primarily for the sale of mining equipment in 2015, administrative support and management services, as well as materials, provided by PacifiCorp to Bridger Coal. Receivables for these services, as well as for certain expenses paid by PacifiCorp and reimbursed by Bridger Coal, were $5 million and $5 million as of December 31, 2017 and 2016, respectively. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2017, 2016 and 2015, coal purchases from PacifiCorp's equity investees totaled $170 million, $174 million and $181 million, respectively. Payables to PacifiCorp's equity investees were $18 million and $17 million as of December 31, 2017 and 2016, respectively.

(19) Supplemental Cash Flow Disclosures

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

	2017	2016	2015
Interest paid, net of amounts capitalized	$ 350	$ 350	$ 342
Income taxes paid, net	$ 340	$ 201	$ 40
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 147	$ 101	$ 147
Accounts receivable related to property, plant and equipment sales	$ —	$ —	$ 40

MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

MidAmerican Funding is an Iowa limited liability company whose sole member is BHE. MidAmerican Funding owns all of the outstanding common stock of MHC, which owns all of the common stock of MidAmerican Energy, Midwest Capital and MEC Construction. MHC, MidAmerican Funding and BHE are headquartered in Des Moines, Iowa.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of MidAmerican Funding and its subsidiaries and MidAmerican Energy as presented in this joint filing. Information in Management's Discussion and Analysis related to MidAmerican Energy, whether or not segregated, also relates to MidAmerican Funding. Information related to other subsidiaries of MidAmerican Funding pertains only to the discussion of the financial condition and results of operations of MidAmerican Funding. Where necessary, discussions have been segregated under the heading "MidAmerican Funding" to allow the reader to identify information applicable only to MidAmerican Funding. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with the historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. MidAmerican Energy's and MidAmerican Funding's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

MidAmerican Energy -

MidAmerican Energy's net income for 2017 was $605 million, an increase of $63 million, or 12%, compared to 2016, including $7 million of net expense as a result of the Tax Cuts and Jobs Act enacted on December 22, 2017 (the "2017 Tax Reform"). Excluding the net effect of the 2017 Tax Reform, adjusted net income for 2017 was $612 million, an increase of $70 million, or 13%, compared to 2016. The increase was due to a higher income tax benefit from additional production tax credits of $38 million, the effects of ratemaking and lower pre-tax income, and higher electric gross margins of $76 million, excluding the impact of an increase in electric DSM program revenue (offset in operating expense) of $22 million, partially offset by higher maintenance expense of $52 million due to additional wind-powered generating facilities and the timing of fossil-fueled generation maintenance, higher depreciation and amortization of $21 million due to wind-powered generation and other plant placed in-service and accruals for Iowa regulatory arrangements, partially offset by a December 2016 reduction in depreciation rates, and higher property and other taxes of $7 million. Electric gross margins increased due to higher recoveries through bill riders, higher retail customer volumes, higher wholesale revenue and higher transmission revenue, partially offset by higher coal and purchased power costs. Retail customer volumes increased 2.4% due to industrial growth net of lower residential and commercial volumes from milder temperatures.

MidAmerican Energy's income from continuing operations of $542 million for 2016 increased $96 million, or 22%, compared to 2015 due to higher electric margins of $172 million, higher production tax credits of $39 million and lower fossil-fueled generation operations and maintenance of $35 million, partially offset by higher depreciation and amortization of $72 million from wind-powered generation and other plant placed in service and an accrual related to an Iowa revenue sharing arrangement, higher operations costs recovered through bill riders of $20 million, higher interest expense of $13 million primarily due to the issuance of first mortgage bonds in October 2015 and a lower income tax benefit due to higher pre-tax income and the effects of ratemaking. Electric margins reflect higher retail rates in Iowa, higher retail sales volumes, lower energy costs, higher wholesale revenue and higher transmission revenue.

MidAmerican Funding -

MidAmerican Funding's net income for 2017 was $574 million, an increase of $42 million, or 8%, compared to 2016, including after-tax charges of $17 million related to the tender offer of a portion of its 6.927% Senior Bonds due 2029 and $10 million of net expense as a result of the 2017 Tax Reform. Excluding the net effect of the 2017 Tax Reform and the tender offer, MidAmerican Funding's adjusted net income for 2017 was $601 million, an increase of $69 million, or 13%, compared to 2016. MidAmerican Funding's income from continuing operations for 2016 was $532 million, an increase of $90 million, or 20%, compared to 2015. In addition to the changes in MidAmerican Energy's earnings discussed above, MidAmerican Funding, in 2015, recognized an $8 million after-tax gain on the sale of an investment in a generating facility lease.

Regulated Electric Gross Margin

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

A comparison of key results related to regulated electric gross margin is as follows for the years ended December 31:

	2017	2016	Change		2016	2015	Change	
Gross margin (in millions):								
Operating revenue	$ 2,108	$ 1,985	$ 123	6 %	$ 1,985	$ 1,837	$ 148	8 %
Cost of fuel, energy and capacity[1]	434	409	25	6	409	433	(24)	(6)
Gross margin	$ 1,674	$ 1,576	$ 98	6	$ 1,576	$ 1,404	$ 172	12
Sales (GWh):								
Residential	6,207	6,408	(201)	(3)%	6,408	6,166	242	4 %
Commercial	3,761	3,812	(51)	(1)	3,812	3,806	6	—
Industrial	12,957	12,115	842	7	12,115	11,487	628	5
Other	1,567	1,589	(22)	(1)	1,589	1,583	6	—
Total retail	24,492	23,924	568	2	23,924	23,042	882	4
Wholesale	9,165	8,489	676	8	8,489	8,741	(252)	(3)
Total sales	33,657	32,413	1,244	4	32,413	31,783	630	2
Average number of retail customers (in thousands)	770	760	10	1 %	760	752	8	1 %
Average revenue per MWh:								
Retail	$ 73.88	$ 71.86	$ 2.02	3 %	$ 71.86	$ 69.68	$ 2.18	3 %
Wholesale	$ 23.42	$ 22.95	$ 0.47	2 %	$ 22.95	$ 20.09	$ 2.86	14 %
Heating degree days	5,492	5,321	171	3 %	5,321	5,654	(333)	(6)%
Cooling degree days	1,117	1,314	(197)	(15)%	1,314	1,067	247	23 %
Sources of energy (GWh)[1]:								
Coal	13,598	13,179	419	3 %	13,179	15,525	(2,346)	(15)%
Wind and other[2]	12,932	11,684	1,248	11	11,684	9,606	2,078	22
Nuclear	3,850	3,912	(62)	(2)	3,912	3,885	27	1
Natural gas	360	556	(196)	(35)	556	199	357	179
Total energy generated	30,740	29,331	1,409	5	29,331	29,215	116	—
Energy purchased	3,603	3,882	(279)	(7)	3,882	3,194	688	22
Total	34,343	33,213	1,130	3	33,213	32,409	804	2

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

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

For 2017 compared to 2016, regulated electric gross margin increased $98 million primarily due to:

(1) Higher retail gross margin of $51 million due to -

- an increase of $73 million from higher recoveries through bill riders, including $22 million of electric DSM program revenue (offset in operating expense);
- an increase of $32 million from non-weather-related usage factors, including higher industrial sales volumes; partially offset by
- a decrease of $33 million from higher retail energy costs primarily due to higher coal-fueled generation and higher purchased power costs; and
- a decrease of $21 million from the impact of milder temperatures;

(2) Higher wholesale gross margin of $32 million due to higher margins per unit from higher market prices, greater availability of lower cost generation for wholesale purposes and higher sales volumes; and

(3) Higher Multi-Value Projects ("MVP") transmission revenue of $13 million due to continued capital additions.

For 2016 compared to 2015, regulated electric gross margin increased $172 million primarily due to:

(1) Higher retail gross margin of $118 million due to -

- an increase of $47 million from higher electric rates in Iowa effective January 1, 2016, for the third step of a 2014 Iowa rate increase;
- an increase of $33 million primarily from non-weather-related usage factors, including higher industrial sales volumes;
- an increase of $27 million from the impact of temperatures;
- an increase of $13 million from lower retail energy costs due to a lower average cost of fuel for generation and lower coal-fueled generation; partially offset by
- a decrease of $2 million from lower recoveries through bill riders;

(2) Higher wholesale gross margin of $37 million due to higher margins per unit from greater availability of lower cost generation for wholesale purposes, partially offset by lower sales volumes attributable to lower coal-fueled generation; and

(3) Higher MVP transmission revenue of $17 million, which is expected to increase as projects are constructed.

Regulated Gas Gross Margin

Operating revenue and cost of gas sold are the key drivers of MidAmerican Energy's regulated gas results of operations as they encompass retail and wholesale natural gas revenue and the direct costs associated with providing natural gas to customers. MidAmerican Energy believes that a discussion of gross margin, representing operating revenue less cost of gas sold, is therefore meaningful.

A comparison of key results related to regulated gas gross margin is as follows for the years ended December 31:

	2017	2016	Change		2016	2015	Change	
Gross margin (in millions):								
Operating revenue	$ 719	$ 637	$ 82	13%	$ 637	$ 661	$ (24)	(4)%
Cost of gas sold	441	367	74	20	367	397	(30)	(8)
Gross margin	$ 278	$ 270	$ 8	3	$ 270	$ 264	$ 6	2
Natural gas throughput (000's Dths):								
Residential	46,366	46,020	346	1%	46,020	46,519	(499)	(1)%
Commercial	23,434	23,345	89	—	23,345	23,466	(121)	(1)
Industrial	4,725	5,079	(354)	(7)	5,079	4,833	246	5
Other	38	37	1	3	37	37	—	—
Total retail sales	74,563	74,481	82	—	74,481	74,855	(374)	—
Wholesale sales	39,735	38,813	922	2	38,813	35,250	3,563	10
Total sales	114,298	113,294	1,004	1	113,294	110,105	3,189	3
Gas transportation service	92,136	83,610	8,526	10	83,610	80,001	3,609	5
Total natural gas throughput	206,434	196,904	9,530	5	196,904	190,106	6,798	4
Average number of retail customers (in thousands)	751	742	9	1%	742	733	9	1 %
Average revenue per retail Dth sold	$ 7.64	$ 6.85	$ 0.79	12%	$ 6.85	$ 7.12	$ (0.27)	(4)%
Average cost of natural gas per retail Dth sold	$ 4.41	$ 3.70	$ 0.71	19%	$ 3.70	$ 4.03	$ (0.33)	(8)%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 3.86	$ 3.24	$ 0.62	19%	$ 3.24	$ 3.61	$ (0.37)	(10)%
Heating degree days	5,788	5,616	172	3%	5,616	5,913	(297)	(5)%

Regulated gas revenue includes purchased gas adjustments clauses ("PGAs") through which MidAmerican Energy is allowed to recover the cost of gas sold from its retail gas utility customers. Consequently, fluctuations in the cost of gas sold do not directly affect gross margin or net income because regulated gas revenue reflects comparable fluctuations through the PGAs. For 2017, MidAmerican Energy's combined retail and wholesale average per-unit cost of gas sold increased 19%, resulting in an increase of $67 million in gas revenue and cost of gas sold compared to 2016. For 2016, MidAmerican Energy's combined retail and wholesale average per-unit cost of gas sold decreased 10%, resulting in a decrease of $42 million in gas revenue and cost of gas sold compared to 2015. Additionally, fluctuations in gas wholesale sales impact gas revenue and cost of gas sold but do not affect regulated gas gross margin.

For 2017 compared to 2016, regulated gas gross margin increased $8 million due to:

(1) higher DSM program revenue (offset in operations and maintenance expense) of $3 million;

(2) higher retail sales volumes of $2 million from colder winter temperatures;

(3) higher gas transportation throughput of $2 million and

(4) higher average per-unit margin of $2 million.

For 2016 compared to 2015, regulated gas gross margin increased $6 million due to:

(1) higher DSM program revenue (offset in operations and maintenance expense) of $6 million;

(2) higher gas transportation throughput of $2 million;

(3) higher average per-unit margin of $1 million, partially offset by

(4) lower retail sales volumes of $3 million from warmer winter temperatures.

Regulated Operating Costs and Expenses

Operations and maintenance increased $88 million for 2017 compared to 2016 due to higher DSM program expense of $25 million and higher transmission operations costs from MISO of $6 million, both of which are recoverable in bill riders and offset in operating revenue, higher coal-fueled and nuclear generation maintenance of $22 million substantially due to the timing of coal-fueled generation outages, higher wind-powered generation maintenance of $18 million from additional wind turbines and higher electric distribution and transmission maintenance of $12 million due to tree trimming costs.

Operations and maintenance decreased $12 million for 2016 compared to 2015 due to lower fossil-fueled generation maintenance of $24 million from the timing of planned outages, lower generation operations of $7 million, lower health care, information technology and other administrative costs of $7 million and lower electric and gas distribution costs of $6 million, partially offset by higher DSM program costs of $11 million and higher transmission operations costs from MISO of $9 million, both of which are recoverable in bill riders and matched by increases in revenue, and higher wind-powered generation maintenance of $13 million due to the addition of wind turbines.

Depreciation and amortization increased $21 million for 2017 compared to 2016 due to utility plant additions, including wind-powered generating facilities placed in-service in the second half of 2016, accruals for Iowa regulatory arrangements of $15 million, partially offset by $31 million from lower depreciation rates implemented in December 2016.

Depreciation and amortization increased $72 million for 2016 compared to 2015 primarily due to additional wind-powered generating facilities placed in-service in the second half of 2015 and the fourth quarter of 2016 and $34 million for accruals for regulatory arrangements in Iowa that reduce electric utility net plant.

Property and other taxes increased $7 million for 2017 compared to 2016 due to higher Iowa replacement taxes from higher sales volumes and higher wind turbine property taxes.

Other Income and (Expense)

MidAmerican Energy -

Interest expense increased $18 million for 2017 compared to 2016 due to higher interest expense from the issuance of $850 million of first mortgage bonds in February 2017 and $30 million of variable rate tax-exempt bonds in December 2016, partially offset by the redemption of $250 million of 5.95% Senior Notes in February 2017. Refer to Note 9 of Notes to Financial Statements in Item 8 of this Form 10-K for further discussion of first mortgage bonds.

Interest expense increased $13 million for 2016 compared to 2015 primarily due to higher interest expense from the issuance of $650 million of first mortgage bonds in October 2015, partially offset by the payment of a $426 million turbine purchase obligation in December 2015.

Allowance for borrowed and equity funds increased $29 million for 2017 compared to 2016 primarily due to higher construction work-in-progress balances related to the construction of wind-powered generating facilities and the wind turbine repowering project.

Other, net increased $5 million for 2017 compared to 2016 due to higher returns from corporate-owned life insurance policies and higher interest income from favorable cash positions, partially offset by a gain of $5 million in 2016 on the redemption of MidAmerican Energy's investments in auction rate securities.

Other, net increased $9 million for 2016 compared to 2015 due to a gain of $5 million on the redemption of MidAmerican Energy's investments in auction rate securities and higher returns from corporate-owned life insurance policies.

MidAmerican Funding -

In addition to the fluctuations discussed above for MidAmerican Energy, MidAmerican Funding's *other, net* for 2017 reflects a pre-tax charge of $29 million from the early redemption of a portion of MidAmerican Funding's 6.927% Senior Bonds due 2029, for 2016 reflects income of $2 million from a partnership's sale of a real estate investment, for 2015 reflects a $13 million pre-tax gain on the sale of an investment in a generating facility lease.

Income Tax Benefit

MidAmerican Energy -

MidAmerican Energy's income tax benefit increased $51 million for 2017 compared to 2016, and the effective tax rate was (43)% for 2017 and (32)% for 2016. The change in the effective tax rate was substantially due to an increase of $38 million in production tax credits and the effects of ratemaking, partially offset by the impact of the 2017 Tax Reform and higher pre-tax income.

MidAmerican Energy's income tax benefit on continuing operations decreased $15 million for 2016 compared to 2015, and the effective tax rate was (32)% for 2016 and (49)% for 2015. The change in the effective tax rate was substantially due to higher pre-tax income, partially offset by an increase of $39 million in production tax credits.

Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold based on a prescribed per-kilowatt rate pursuant to the applicable federal income tax law and are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service. Beginning in late 2014, some of MidAmerican Energy's wind-powered generating facilities surpassed the 10-year eligibility period and are no longer earning the credits. A credit per kilowatt hour of $0.024 for 2017 and $0.023 for 2016 and 2015 was applied to annual production, which resulted in $287 million, $249 million and $210 million, respectively, in production tax credits.

MidAmerican Funding -

MidAmerican Funding's income tax benefit increased $63 million for 2017 compared to 2016, and the effective tax rate was (54)% for 2017 and (35)% for 2016. MidAmerican Funding's income tax benefit on continuing operations decreased $11 million for 2016 compared to 2015, and the effective tax rate was (35)% for 2016 and (51)% for 2015. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy. Additionally, 2017 reflects an income tax benefit from a charge of $29 million for the early redemption of a portion of MidAmerican Funding's 6.927% Senior Bonds due 2029, and 2015 reflects income taxes on a $13 million gain from the sale of an investment in a generating facility lease.

Liquidity and Capital Resources

As of December 31, 2017, MidAmerican Energy's total net liquidity was $707 million consisting of $172 million of cash and cash equivalents and $905 million of credit facilities reduced by $370 million of the credit facilities reserved to support MidAmerican Energy's variable-rate tax-exempt bond obligations. As of December 31, 2017, MidAmerican Funding's total net liquidity was $711 million, including MHC's $4 million credit facility.

Cash Flows From Operating Activities

MidAmerican Energy's net cash flows from operating activities were $1,396 million, $1,403 million and $1,351 million for 2017, 2016 and 2015, respectively. MidAmerican Funding's net cash flows from operating activities were $1,380 million, $1,393 million and $1,335 million for 2017, 2016 and 2015, respectively. Cash flows from operating activities decreased for 2017 compared to 2016 primarily due to lower income tax receipts and higher interest payments, partially offset by higher cash margins for MidAmerican Energy's regulated electric business, including a reduction in fuel inventories. The increase in net cash flows from operating activities for 2016 compared to 2015 was primarily due to higher cash margins for MidAmerican Energy's regulated electric business, partially offset by a growth in receivables net of payables, lower derivative collateral cash flows, higher payments for asset retirement obligation settlements, and the timing of DSM cost recovery cash flows.

MidAmerican Energy's income tax cash flows benefited in 2017, 2016 and 2015 from 50% bonus depreciation on qualifying assets placed in service and from production tax credits earned on qualifying projects. In December 2017, the 2017 Tax Reform was enacted which, among other items, reduces the federal corporate tax rate from 35% to 21% effective January 1, 2018 and eliminates bonus depreciation on qualifying regulated utility assets acquired after September 27, 2017, but did not impact production tax credits. MidAmerican Energy believes for qualifying assets acquired on or before September 27, 2017, bonus depreciation will be available for 2018 and 2019. MidAmerican Energy anticipates passing the benefits of lower tax expense to customers in the form of either rate reductions or rate base reductions. MidAmerican Energy expects lower revenue and income taxes as well as lower bonus depreciation benefits as a result of the 2017 Tax Reform and related regulatory treatment. MidAmerican Energy does not expect the 2017 Tax Reform and related regulatory treatment to have a material adverse impact on its cash flows, subject to actual regulatory outcomes. Refer to Regulatory Matters in Item 1 of this Form 10-K for further discussion of regulatory matters associated with the 2017 Tax Reform. The timing of MidAmerican Energy's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

Internal Revenue Service ("IRS") rules provide for re-establishment of the production tax credit for an existing wind-powered generating facility upon the replacement of a significant portion of its components. Such component replacement is commonly referred to as repowering. If the degree of component replacement in such projects meets IRS guidelines, production tax credits are re-established for ten years at rates that depend upon the date in which construction begins, as noted in the above paragraph. MidAmerican Energy's current repowering projects are expected to earn production tax credits at 100% of the value of such credits.

Cash Flows From Investing Activities

MidAmerican Energy's net cash flows from investing activities were $(1,874) million, $(1,615) million and $(1,450) million for 2017, 2016 and 2015, respectively. MidAmerican Funding's net cash flows from investing activities were $(1,877) million, $(1,614) million and $(1,438) million for 2017, 2016 and 2015, respectively. Net cash flows from investing activities consist almost entirely of utility construction expenditures. Refer to "Future Uses of Cash" for further discussion of utility construction expenditures. Purchases and proceeds related to available-for-sale securities consist of activity within the Quad Cities Generating Station nuclear decommissioning trust and, in 2016, proceeds from the redemption of MidAmerican Energy's investments in auction rate securities. MidAmerican Funding received $13 million in 2015 related to the sale of an investment in a generating facility lease. Restricted cash and short-term investments activity for 2017 and 2016 relates to restricted proceeds from Solid Waste Facilities Revenue Bonds issued by the Iowa Finance Authority in 2017 and 2016, as discussed below.

Cash Flows From Financing Activities

MidAmerican Energy's net cash flows from financing activities were $636 million, $123 million and $173 million for 2017, 2016 and 2015, respectively. MidAmerican Funding's net cash flows from financing activities were $654 million, $133 million and $176 million for 2017, 2016 and 2015, respectively. In December 2017, the Iowa Finance Authority issued $150 million of its variable-rate, tax-exempt Solid Waste Facilities Revenue Bonds due December 2047, the restricted proceeds of which were loaned to MidAmerican Energy for the purpose of constructing solid waste facilities. In February 2017, MidAmerican Energy issued $375 million of its 3.10% First Mortgage Bonds due May 2027 and $475 million of its 3.95% First Mortgage Bonds due August 2047. An amount equal to the net proceeds was used to finance capital expenditures disbursed during the period from February 2, 2016 to February 1, 2017, with respect to investments in MidAmerican Energy's 551-megawatt Wind X and 2,000-megawatt Wind XI projects, which were previously financed with MidAmerican Energy's general funds. In February 2017, MidAmerican Energy redeemed in full through optional redemption its $250 million of 5.95% Senior Notes due July 2017. In December 2016, the Iowa Finance Authority issued $30 million of its variable-rate, tax-exempt Solid Waste Facilities Revenue Bonds due December 2046, the proceeds of which were loaned to MidAmerican Energy for the purpose of constructing solid waste facilities. In September 2016, the Iowa Finance Authority issued $33 million of variable-rate, tax-exempt Pollution Control Facilities Refunding Revenue Bonds due September 2036, the proceeds of which were loaned to MidAmerican Energy to refinance, in September 2016, variable-rate tax-exempt pollution control refunding revenue bonds totaling $29 million due September 2016 and $4 million due March 2017, which were optionally redeemed in full. In October 2015, MidAmerican Energy issued $200 million of 3.50% First Mortgage Bonds due October 2024 and $450 million of 4.25% First Mortgage Bonds due May 2046. The net proceeds were used for the payment of a $426 million turbine purchase obligation due December 2015 and for general corporate purposes. Through its commercial paper program, MidAmerican Energy made repayments totaling $99 million in 2017, received $99 million in 2016 and made repayments totaling $50 million in 2015.

In December 2017, MidAmerican Funding redeemed through a tender offer a portion of its 6.927% Senior Bonds. MidAmerican Funding received $133 million, $9 million and $3 million in 2017, 2016 and 2015, respectively, through its note payable with BHE.

In February 2018, MidAmerican Energy issued $700 million of its 3.65% First Mortgage Bonds due August 2048.

Debt Authorizations and Related Matters

MidAmerican Energy has authority from the FERC to issue through February 28, 2019, commercial paper and bank notes aggregating $905 million at interest rates not to exceed the applicable London Interbank Offered Rate ("LIBOR") plus a spread of 400 basis points. MidAmerican Energy has a $900 million unsecured credit facility expiring in June 2020 for which MidAmerican Energy may request that the banks extend the credit facility up to two years. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Eurodollar rate or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a $5 million unsecured credit facility for general corporate purposes.

MidAmerican Energy currently has an effective registration statement with the SEC to issue an indeterminate amount of long-term debt securities through September 16, 2018. Additionally, following the February 2018 issuance of $700 million of first mortgage bonds, MidAmerican Energy has authorization from the FERC to issue, through August 31, 2019, preferred stock up to an aggregate of $500 million and long-term debt securities up to an aggregate of $1.5 billion at interest rates not to exceed the applicable United States Treasury rate plus a spread of 175 basis points and from the ICC to issue preferred stock up to an aggregate of $500 million through November 1, 2020, and additional long-term debt securities up to an aggregate of $1.5 billion, of which $500 million expires March 15, 2019, and $1.0 billion expires November 1, 2020.

In conjunction with the March 1999 merger, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval of the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. If MidAmerican Energy's common equity level were to drop below the required thresholds, MidAmerican Energy's ability to issue debt could be restricted. As of December 31, 2017, MidAmerican Energy's common equity ratio was 53% computed on a basis consistent with its commitment. As a result of MidAmerican Energy's regulatory commitment to maintain its common equity above certain thresholds, MidAmerican Energy could dividend $2.1 billion as of December 31, 2017, without falling below 42%, and MidAmerican Funding had restricted net assets of $3.7 billion.

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

Future Uses of Cash

MidAmerican Energy and MidAmerican Funding have available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which MidAmerican Energy and MidAmerican Funding have access to external financing depends on a variety of factors, including their credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

MidAmerican Energy's primary need for capital is utility construction expenditures. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

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

	Historical			Forecast		
	2015	2016	2017	2018	2019	2020
Wind-powered generation development	$ 931	$ 943	$ 657	$ 1,132	$ 1,038	$ 329
Wind-powered generation repowering	—	67	514	248	205	123
Transmission Multi-Value Projects	156	119	21	46	—	—
Other	359	507	581	970	468	445
Total	$ 1,446	$ 1,636	$ 1,773	$ 2,396	$ 1,711	$ 897

MidAmerican Energy's historical and forecast capital expenditures include the following:

- The construction of wind-powered generating facilities in Iowa. MidAmerican Energy placed in-service 334 MW (nominal ratings) during 2017, 600 MW (nominal ratings) during 2016 and 608 MW (nominal ratings) during 2015. In August 2016, the IUB issued an order approving ratemaking principles related to MidAmerican Energy's construction of up to 2,000 MW (nominal ratings) of additional wind-powered generating facilities, including the additions in 2017 and facilities expected to be placed in-service in 2018 and 2019. The ratemaking principles establish a cost cap of $3.6 billion, including AFUDC, and a fixed rate of return on equity of 11.0% over the proposed 40-year useful lives of those facilities in any future Iowa rate proceeding. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. Additionally, the ratemaking principles modify the revenue sharing mechanism currently in effect. The revised sharing mechanism will be effective in 2018 and will be triggered each year by actual equity returns exceeding a weighted average return on equity for MidAmerican Energy calculated annually. Pursuant to the change in revenue sharing, MidAmerican Energy will share 100% of the revenue in excess of this trigger with customers. Such revenue sharing will reduce coal and nuclear generation rate base, which is intended to mitigate future base rate increases. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for 100% of federal production tax credits available.
- The repowering of certain existing wind-powered generating facilities in Iowa. This project entails the replacement of significant components of the oldest turbines in MidAmerican Energy's fleet. The energy production from such repowered facilities is expected to qualify for 100% of the federal production tax credits available for ten years following each facility's return to service. Under MidAmerican Energy's Iowa electric tariff, federal production tax credits related to facilities that were in-service prior to 2013 must be included in its Iowa energy adjustment clause. In August 2017, the IUB approved a tariff change that excludes from MidAmerican Energy's Iowa energy adjustment clause any future federal production tax credits related to these repowered facilities. In 2017, facilities accounting for 414 MW and $465 million of repowering expenditures were placed in-service.
- Transmission MVP investments. In 2012, MidAmerican Energy started the construction of four MISO-approved MVPs located in Iowa and Illinois. When complete, the four MVPs will have added approximately 250 miles of 345 kV transmission line to MidAmerican Energy's transmission system and will be owned and operated by MidAmerican Energy. As of December 31, 2017, 224 miles of these MVP transmission lines have been placed in-service.
- Remaining expenditures primarily relate to routine operating projects for distribution, generation, transmission and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

MidAmerican Energy and MidAmerican Funding have contractual cash obligations that may affect their financial condition. The following table summarizes the material contractual cash obligations of MidAmerican Energy and MidAmerican Funding as of December 31, 2017 (in millions):

	Payments Due By Periods				
	2018	2019-2020	2021-2022	2023 and After	Total
MidAmerican Energy:					
Long-term debt	$ 350	$ 503	$ —	$ 4,227	$ 5,080
Interest payments on long-term debt[(1) (2)]	203	371	365	2,621	3,560
Coal, electricity and natural gas contract commitments[(1)]	268	278	159	85	790
Construction commitments[(1)]	790	30	—	—	820
Easements and operating leases[(1)]	22	42	42	713	819
Other commitments[(1)]	96	221	268	233	818
	1,729	1,445	834	7,879	11,887
MidAmerican Funding parent:					
Long-term debt	—	—	—	239	239
Interest payments on long-term debt[(1)]	17	33	33	108	191
	17	33	33	347	430
Total contractual cash obligations	$ 1,746	$ 1,478	$ 867	$ 8,226	$ 12,317

(1) Not reflected on the Consolidated Balance Sheets.

(2) Includes interest payments for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are assumed to equal December 31, 2017 rates.

MidAmerican Energy has other types of commitments that relate primarily to construction expenditures (in "Utility Construction Expenditures" section above) and asset retirement obligations beyond 2017 (Note 12), which have not been included in the above table because the amount or timing of the cash payments is not certain. Refer to Notes 9, 12 and 15 in Notes to Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

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

Quad Cities Generating Station Operating Status

Exelon Generation Company, LLC ("Exelon Generation"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, announced on June 2, 2016, its intention to shut down Quad Cities Station on June 1, 2018, as a result of Illinois not passing adequate legislation and Quad Cities Station not clearing the 2019-2020 PJM Interconnection, L.L.C. capacity auction. MidAmerican Energy expressed to Exelon Generation its desire for the continued operation of the facility through the end of its operating license in 2032 and worked with Exelon Generation on solutions to that end. In December 2016, Illinois passed legislation creating a zero emission standard, which went into effect June 1, 2017. The zero emission standard requires the Illinois Power Agency to purchase zero emission credits and recover the costs from certain ratepayers in Illinois, subject to certain limitations. The proceeds from the zero emission credits will provide Exelon Generation additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. For the nuclear assets already in rate base, MidAmerican Energy's customers will not be charged for the subsidy, and MidAmerican Energy will not receive additional revenue from the subsidy.

On February 14, 2017, two lawsuits were filed with the United States District Court for the Northern District of Illinois ("Northern District of Illinois") against the Illinois Power Agency alleging that the state's zero emission credit program violates certain provisions of the U.S. Constitution. Both complaints argue that the Illinois zero emission credit program will distort the FERC's energy and capacity market auction system of setting wholesale prices. As majority owner and operator of Quad Cities Station, Exelon Generation intervened and filed motions to dismiss in both lawsuits. On July 14, 2017, the Northern District of Illinois granted the motions to dismiss. On July 17, 2017, the plaintiffs filed appeals with the United States Court of Appeals for the Seventh Circuit. Parties have filed briefs and presented oral argument. MidAmerican Energy cannot predict the outcome of these lawsuits.

On January 9, 2017, the Electric Power Supply Association filed two requests with the FERC seeking to expand Minimum Offer Price Rule ("MOPR") provisions to apply to existing resources receiving zero emission credit compensation. If successful, an expanded MOPR could result in an increased risk of Quad Cities Station not clearing in future capacity auctions and Exelon Generation no longer receiving capacity revenues for the facility. As majority owner and operator of Quad Cities Station, Exelon Generation has filed protests at the FERC in response to each filing. The timing of the FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Environmental Laws and Regulations

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

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for MidAmerican Energy's forecast environmental-related capital expenditures.

Collateral and Contingent Features

Debt securities of MidAmerican Energy are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of MidAmerican Energy's ability to, in general, meet the obligations of its issued debt securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2017, MidAmerican Energy's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the three recognized credit rating agencies were investment grade. As a result of the issuance of first mortgage bonds by MidAmerican Energy in September 2013, its then outstanding senior unsecured debt was equally and ratably secured with such first mortgage bonds. Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's first mortgage bonds.

MidAmerican Funding and MidAmerican Energy have no credit rating downgrade triggers that would accelerate the maturity dates of its outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. MidAmerican Energy's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base MidAmerican Energy's collateral requirements on its credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2017, MidAmerican Energy would have been required to post $114 million of additional collateral. MidAmerican Energy's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 13 of Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's collateral requirements specific to its derivative contracts.

Inflation

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

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting MidAmerican Energy and MidAmerican Funding, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, that could limit MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes the application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $204 million and total regulatory liabilities were $1,661 million as of December 31, 2017. Refer to Note 6 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory assets and liabilities.

Income Taxes

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory jurisdictions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of their federal, state and local tax examinations is uncertain, each company believes it has made adequate provisions for its income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on its consolidated financial results. Refer to Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes.

It is probable that MidAmerican Energy will pass income tax benefits and expenses related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to its customers. As of December 31, 2017, these amounts were recognized as a net regulatory liability of $681 million and will be included in regulated rates when the associated temporary differences reverse.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2017, includes goodwill from the acquisition of MHC totaling $1.3 billion. Goodwill is allocated to each reporting unit. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2017. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors.

Pension and Other Postretirement Benefits

MidAmerican Energy sponsors defined benefit pension and other postretirement benefit plans that cover the majority of the employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy Inc. MidAmerican Energy recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2017, MidAmerican Energy recognized a net liability totaling $23 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2017, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled $38 million and $41 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. MidAmerican Energy believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 11 of Notes to Financial Statements in Item 8 of this Form 10-K for disclosures about MidAmerican Energy's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2017.

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

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

MidAmerican Energy chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5% by 2025 at which point the rate of increase is assumed to remain constant. Refer to Note 11 of Notes to Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and the funded status. If changes were to occur for the following key assumptions, the approximate effect on the Financial Statements of the total plan before allocations to affiliates would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2017 Benefit Obligations:				
Discount rate	$ (38)	$ 42	$ (10)	$ 10
Effect on 2017 Periodic Cost:				
Discount rate	1	(2)	—	—
Expected rate of return on plan assets	(3)	3	(1)	1

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

Revenue Recognition - Unbilled Revenue

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters and rates. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $89 million as of December 31, 2017. 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. Unbilled revenue is reversed in the following month, and billed revenue is recorded based on the subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

MidAmerican Energy's Balance Sheets include assets and liabilities with fair values that are subject to market risks. MidAmerican Energy's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which it transacts. The following discussion addresses the significant market risks associated with MidAmerican Energy's business activities. MidAmerican Energy has established guidelines for credit risk management. Refer to Notes 2 and 13 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's contracts accounted for as derivatives.

Commodity Price Risk

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. 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. Commodity price risk for MidAmerican Energy's regulated retail electricity and natural gas operations is significantly mitigated by the inclusion of energy costs in energy cost rider mechanisms, which permit the current recovery of such costs from its retail customers. MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements to mitigate price volatility on behalf of its customers. MidAmerican Energy does not engage in a material amount of proprietary trading activities, and following the January 1, 2016 transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE, MidAmerican Energy no longer provides nonregulated retail electricity and natural gas services in competitive markets.

Interest Rate Risk

MidAmerican Energy and MidAmerican Funding are exposed to interest rate risk on their outstanding variable-rate short- and long-term debt and future debt issuances. MidAmerican Energy and MidAmerican Funding manage interest rate risk by limiting their exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the fixed-rate long-term debt does not expose MidAmerican Energy or MidAmerican Funding to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if MidAmerican Energy or MidAmerican Funding were to reacquire all or a portion of these instruments prior to their maturity. MidAmerican Energy or MidAmerican Funding may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate their exposure to interest rate risk. The nature and amount of their short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 8, 9 and 14 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of MidAmerican Energy's and MidAmerican Funding's short- and long-term debt.

As of December 31, 2017 and 2016, MidAmerican Energy had short- and long-term variable-rate obligations totaling $370 million and $319 million, respectively, that expose MidAmerican Energy to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to MidAmerican Energy's variable-rate debt as of December 31, 2017, is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on MidAmerican Energy's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2017 and 2016.

Credit Risk

MidAmerican Energy is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Additionally, MidAmerican Energy participates in the regional transmission organization ("RTO") markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MidAmerican Energy enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MidAmerican Energy exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2017, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MidAmerican Energy Company
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying balance sheets of MidAmerican Energy Company ("MidAmerican Energy") as of December 31, 2017 and 2016, and the related statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15(a)(ii) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of MidAmerican Energy as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MidAmerican Energy's management. Our responsibility is to express an opinion on MidAmerican Energy's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to MidAmerican Energy in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. MidAmerican Energy is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Energy’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 23, 2018

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2017	**2016**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 172	$ 14
Receivables, net	344	285
Income taxes receivable	51	9
Inventories	245	264
Other current assets	134	35
Total current assets	946	607
Property, plant and equipment, net	14,207	12,821
Regulatory assets	204	1,161
Investments and restricted cash and investments	728	653
Other assets	233	217
Total assets	$ 16,318	$ 15,459

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

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2017	**2016**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 452	$ 303
Accrued interest	48	45
Accrued property, income and other taxes	132	137
Short-term debt	—	99
Current portion of long-term debt	350	250
Other current liabilities	128	159
Total current liabilities	1,110	993
Long-term debt	4,692	4,051
Deferred income taxes	2,237	3,572
Regulatory liabilities	1,661	883
Asset retirement obligations	528	510
Other long-term liabilities	326	290
Total liabilities	10,554	10,299
Commitments and contingencies (Note 15)		
Shareholder's equity:		
Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding	—	—
Additional paid-in capital	561	561
Retained earnings	5,203	4,599
Total shareholder's equity	5,764	5,160
Total liabilities and shareholder's equity	$ 16,318	$ 15,459

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Operating revenue:			
Regulated electric	$ 2,108	$ 1,985	$ 1,837
Regulated gas and other	729	640	665
Total operating revenue	2,837	2,625	2,502
Operating costs and expenses:			
Cost of fuel, energy and capacity	434	409	433
Cost of gas sold and other	442	367	398
Operations and maintenance	781	693	705
Depreciation and amortization	500	479	407
Property and other taxes	119	112	110
Total operating costs and expenses	2,276	2,060	2,053
Operating income	561	565	449
Other income and (expense):			
Interest expense	(214)	(196)	(183)
Allowance for borrowed funds	15	8	8
Allowance for equity funds	41	19	20
Other, net	19	14	5
Total other income and (expense)	(139)	(155)	(150)
Income before income tax benefit	422	410	299
Income tax benefit	(183)	(132)	(147)
Income from continuing operations	605	542	446
Discontinued operations (Note 3):			
Income from discontinued operations	—	—	22
Income tax expense	—	—	6
Income on discontinued operations	—	—	16
Net income	$ 605	$ 542	$ 462

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2017	2016	2015
Net income	$ 605	$ 542	$ 462
Other comprehensive income (loss), net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $-, $1 and $-	—	3	—
Unrealized losses on cash flow hedges, net of tax of $-, $- and $(4)	—	—	(7)
Total other comprehensive income (loss), net of tax	—	3	(7)
Comprehensive income	$ 605	$ 545	$ 455

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Equity
Balance, December 31, 2014	$ 561	$ 3,712	$ (23)	$ 4,250
Net income	—	462	—	462
Other comprehensive loss	—	—	(7)	(7)
Balance, December 31, 2015	561	4,174	(30)	4,705
Net income	—	542	—	542
Other comprehensive income	—	—	3	3
Dividend (Note 3)	—	(117)	27	(90)
Balance, December 31, 2016	561	4,599	—	5,160
Net income	—	605	—	605
Other equity transactions	—	(1)	—	(1)
Balance, December 31, 2017	$ 561	$ 5,203	$ —	$ 5,764

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 605	$ 542	$ 462
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	500	479	407
Deferred income taxes and amortization of investment tax credits	332	361	275
Changes in other assets and liabilities	37	47	49
Other, net	(59)	(91)	(58)
Changes in other operating assets and liabilities:			
Receivables, net	(58)	(61)	91
Inventories	19	(27)	(53)
Derivative collateral, net	2	5	33
Pension and other postretirement benefit plans, net	(11)	(6)	(8)
Accounts payable	69	39	(76)
Accrued property, income and other taxes, net	(41)	107	217
Other current assets and liabilities	1	8	12
Net cash flows from operating activities	1,396	1,403	1,351
Cash flows from investing activities:			
Utility construction expenditures	(1,773)	(1,636)	(1,446)
Purchases of available-for-sale securities	(143)	(138)	(142)
Proceeds from sales of available-for-sale securities	137	158	135
Net increase in restricted cash and short-term investments	(98)	(10)	—
Other, net	3	11	3
Net cash flows from investing activities	(1,874)	(1,615)	(1,450)
Cash flows from financing activities:			
Proceeds from long-term debt	990	62	649
Repayments of long-term debt	(255)	(38)	(426)
Net (repayments of) proceeds from short-term debt	(99)	99	(50)
Net cash flows from financing activities	636	123	173
Net change in cash and cash equivalents	158	(89)	74
Cash and cash equivalents at beginning of year	14	103	29
Cash and cash equivalents at end of year	$ 172	$ 14	$ 103

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

MIDAMERICAN ENERGY COMPANY
NOTES TO FINANCIAL STATEMENTS

(1) Company Organization

MidAmerican Energy Company ("MidAmerican Energy") is a public utility with electric and natural gas operations and is the principal subsidiary of MHC Inc. ("MHC"). MHC is a holding company that conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's nonregulated subsidiaries include Midwest Capital Group, Inc. and MEC Construction Services Co. MHC is the direct wholly owned subsidiary of MidAmerican Funding, LLC, ("MidAmerican Funding"), which is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Use of Estimates in Preparation of Financial Statements

The preparation of the Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Financial Statements.

A*ccounting for the Effects of Certain Types of Regulation*

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Board ("IUB"), the Illinois Commerce Commission ("ICC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). MidAmerican Energy's accounting policies and the accompanying Financial Statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, that could limit MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes the application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Investments

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

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on securities in a trust related to the decommissioning of the Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") are recorded as a net regulatory liability because MidAmerican Energy expects to recover costs for these activities through regulated rates. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity.

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

Allowance for Doubtful Accounts

Receivables are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on MidAmerican Energy's assessment of the collectibility of amounts owed to it by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. As of December 31, 2017 and 2016, the allowance for doubtful accounts totaled $7 million and is included in receivables, net on the Balance Sheets.

Derivatives

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

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked to market, and settled amounts are recognized as operating revenue or cost of sales on the Statements of Operations.

For MidAmerican Energy's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities.

For MidAmerican Energy's derivatives designated as hedging contracts, MidAmerican Energy formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. MidAmerican Energy formally documents hedging activity by transaction type and risk management strategy. Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. All of MidAmerican Energy's derivatives designated as cash flow hedges and the related AOCI were transferred to a subsidiary of BHE on January 1, 2016, as discussed in Note 3.

Inventories

Inventories consist mainly of coal stocks, totaling $117 million and $137 million as of December 31, 2017 and 2016, respectively, materials and supplies, totaling $100 million and $99 million as of December 31, 2017 and 2016, respectively, and natural gas in storage, totaling $24 million as of December 31, 2017 and 2016. The cost of materials and supplies, coal stocks and fuel oil is determined using the average cost method. The cost of stored natural gas is determined using the last-in-first-out method. With respect to stored natural gas, the replacement cost would be $22 million and $27 million higher as of December 31, 2017 and 2016, respectively.

Utility Plant, Net

General

Additions to utility plant are recorded at cost. MidAmerican Energy capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC") and equity AFUDC. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds and energy benefits associated with certain wind-powered generation. Amounts expensed under this arrangement are included as a component of depreciation and amortization.

Depreciation and amortization for MidAmerican Energy's utility operations are computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by its various regulatory authorities. Depreciation studies are completed by MidAmerican Energy to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally, when MidAmerican Energy retires or sells a component of utility plant, it charges the original cost, net of any proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of nonregulated assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of its regulated facilities, is capitalized by MidAmerican Energy as a component of utility plant, with offsetting credits to the Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, MidAmerican Energy is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

MidAmerican Energy recognizes AROs when it has a legal obligation to perform decommissioning or removal activities upon retirement of an asset. MidAmerican Energy's AROs are primarily related to decommissioning of the Quad Cities Station and obligations associated with its other generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to utility plant) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

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

Revenue Recognition

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2017 and 2016, unbilled revenue was $89 million and $87 million, respectively, and is included in receivables, net on the Balance Sheets.

The determination of customer billings is based on a systematic reading of customer meters and applicable rates. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

All of MidAmerican Energy's regulated retail electric and gas sales are subject to energy adjustment clauses. MidAmerican Energy also has costs that are recovered, at least in part, through bill riders, including demand-side management and certain transmission costs. The clauses and riders allow MidAmerican Energy to adjust the amounts charged for electric and gas service as the related costs change. The costs recovered in revenue through use of the adjustment clauses and bill riders are charged to expense in the same year the related revenue is recognized. At any given time, these costs may be over or under collected from customers. The total under collection included in receivables at December 31, 2017 and 2016, was $72 million and $31 million, respectively.

MidAmerican Energy collects from its customers sales and excise taxes assessed by governmental authorities on transactions with customers and later remits the collected taxes to the appropriate authority. If the obligation to pay a particular tax resides with the customer, MidAmerican Energy reports such taxes collected on a net basis and, accordingly, they do not affect the Statement of Operations. Taxes for which the obligation resides with MidAmerican Energy are reported on a gross basis in operating revenue and operating expenses. The amounts reported on a gross basis are not material.

Unamortized Debt Premiums, Discounts and Issuance Costs

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

Income Taxes

Berkshire Hathaway includes MidAmerican Funding and MidAmerican Energy in its consolidated United States federal income tax return. MidAmerican Funding's and MidAmerican Energy's provisions for income taxes have been computed on a stand-alone basis.

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. On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law which, among other items, reduces the federal corporate tax rate from 35% to 21%. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences that MidAmerican Energy deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory jurisdictions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of their federal, state and local income tax examinations is uncertain, each company believes it has made adequate provisions for its income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on its consolidated financial results. MidAmerican Funding's and MidAmerican Energy's unrecognized tax benefits are primarily included in taxes accrued and other long-term liabilities on their respective Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

New Accounting Pronouncements

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, which amends FASB Accounting Standards Codification ("ASC") Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. This guidance must be adopted retrospectively for the presentation of the service cost component and the other components of net benefit cost in the statement of operations and prospectively for the capitalization of the service cost component in the balance sheet. MidAmerican Energy adopted this guidance effective January 1, 2018, and the adoption will not have a material impact on its Financial Statements and disclosures included within Notes to Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, “Statement of Cash Flows - Overall.” The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively, wherein the statement of cash flows of each period presented should be adjusted to reflect the new guidance. MidAmerican Energy adopted this guidance effective January 1, 2018, and the adoption will not have a material impact on its Financial Statements and disclosures included within Notes to Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. MidAmerican Energy adopted this guidance effective January 1, 2018, and the adoption will not have a material impact on its Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. In January 2018, the FASB issued ASU No. 2018-01 that provides for an optional transition practical expedient allowing companies to not have to evaluate existing land easements if they were not previously accounted for under ASC Topic 840, "Leases." This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. MidAmerican Energy plans to adopt this guidance effective January 1, 2019, and is currently evaluating the impact on its Financial Statements and disclosures included within Notes to Financial Statements.

In January 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. MidAmerican Energy adopted this guidance effective January 1, 2018, and the adoption will not have a material impact on its Financial Statements and disclosures included within Notes to Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No.2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. During 2016 and 2017, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. MidAmerican Energy adopted this guidance effective January 1, 2018, under the modified retrospective method and the adoption will not have an impact on its Financial Statements but will increase the disclosures included within Notes to Financial Statements. The timing and amount of revenue recognized after adoption of the new guidance will not be different than before as a majority of revenue is recognized equal to what MidAmerican Energy has the right to invoice as it corresponds directly with the value to the customer of MidAmerican Energy's performance to date. MidAmerican Energy's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by customer class for each segment.

(3) Discontinued Operations

On January 1, 2016, MidAmerican Energy transferred the assets and liabilities of its unregulated retail services business to a subsidiary of BHE. The transfer was made at MidAmerican Energy's carrying value of the assets, liabilities and AOCI as of December 31, 2015, totaling $90 million, and was recorded by MidAmerican Energy as a noncash dividend. Financial results of the unregulated retail services business for the year ended December 31, 2015 have been reclassified to discontinued operations in the Statement of Operations. Significant line items constituting pre-tax income from discontinued operations and total cash flows from operating activities for the years ended December 31 are as follows (in millions):

		2015
Operating revenue	$	905
Cost of sales	$	854
Cash flows from operating activities	$	30

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2017	2016
Utility plant in service:			
Generation	20-70 years	$ 12,107	$ 11,282
Transmission	52-75 years	1,838	1,726
Electric distribution	20-75 years	3,380	3,197
Gas distribution	29-75 years	1,640	1,565
Utility plant in service		18,965	17,770
Accumulated depreciation and amortization		(5,561)	(5,448)
Utility plant in service, net		13,404	12,322
Nonregulated property, net:			
Nonregulated property gross	20-50 years	7	7
Accumulated depreciation and amortization		(1)	(1)
Nonregulated property, net		6	6
		13,410	12,328
Construction work-in-progress		797	493
Property, plant and equipment, net		$ 14,207	$ 12,821

Nonregulated property includes land, computer software and other assets not recoverable for regulated utility purposes.

The average depreciation and amortization rates applied to depreciable utility plant for the years ended December 31 were as follows:

	2017	2016	2015
Electric	2.6%	2.8%	3.0%
Gas	2.7%	2.9%	2.9%

During the fourth quarter of 2016, MidAmerican Energy revised its electric and gas depreciation rates based on the results of a new depreciation study, the most significant impact of which was longer estimated useful lives for certain wind-powered generating facilities. The effect of this change was to reduce depreciation and amortization expense by $3 million in 2016 and $34 million annually based on depreciable plant balances at the time of the change.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, MidAmerican Energy, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. MidAmerican Energy accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Statements of Operations include MidAmerican Energy's share of the expenses of these facilities.

The amounts shown in the table below represent MidAmerican Energy's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2017 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa Unit No. 1	88%	$ 807	$ 432	$ 8
Quad Cities Unit Nos. 1 & 2[(1)]	25	698	387	20
Walter Scott, Jr. Unit No. 3	79	617	316	8
Walter Scott, Jr. Unit No. 4[(2)]	60	456	112	1
George Neal Unit No. 4	41	307	159	1
Ottumwa Unit No. 1	52	567	206	40
George Neal Unit No. 3	72	425	183	7
Transmission facilities	Various	249	87	1
Total		$ 4,126	$ 1,882	$ 86

(1) Includes amounts related to nuclear fuel.

(2) Plant in service and accumulated depreciation and amortization amounts are net of credits applied under Iowa revenue sharing arrangements totaling $319 million and $81 million, respectively.

(6) Regulatory Matters

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

	Average Remaining Life	2017	2016
Deferred income taxes, net[(1)]	N/A	$ —	$ 985
Asset retirement obligations[(2)]	10 years	133	105
Employee benefit plans[(3)]	13 years	38	40
Unrealized loss on regulated derivative contracts	1 year	6	2
Other	Various	27	29
Total		$ 204	$ 1,161

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

(2) Amount predominantly relates to asset retirement obligations for fossil-fueled and wind-powered generating facilities. Refer to Note 12 for a discussion of asset retirement obligations.

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

MidAmerican Energy had regulatory assets not earning a return on investment of $200 million and $1.2 billion as of December 31, 2017 and 2016, respectively.

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

	Average Remaining Life	2017	2016
Cost of removal accrual[1]	28 years	$ 688	$ 665
Deferred income taxes[2]	28 years	681	—
Asset retirement obligations[3]	35 years	173	117
Employee benefit plans[4]	11 years	41	12
Pre-funded AFUDC on transmission MVPs[5]	55 years	35	35
Iowa electric revenue sharing accrual[6]	1 year	26	30
Unrealized gain on regulated derivative contracts	1 year	3	6
Other	Various	14	18
Total		$ 1,661	$ 883

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

(2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse. See Note 10 for further discussion of 2017 Tax Reform impacts.

(3) Amount predominantly represents the excess of nuclear decommission trust assets over the related asset retirement obligation. Refer to Note 12 for a discussion of asset retirement obligations.

(4) 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.

(5) Represents AFUDC accrued on transmission MVPs that is deducted from rate base as a result of the inclusion of related construction work-in-progress in rate base.

(6) Represents current-year accruals under a regulatory arrangement in Iowa in which equity returns exceeding specified thresholds reduce utility plant upon final determination.

(7) Investments and Restricted Cash and Investments

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

	2017	2016
Nuclear decommissioning trust	$ 515	$ 460
Rabbi trusts	198	184
Other	15	9
Total	$ 728	$ 653

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which is currently licensed for operation until December 2032. As of December 31, 2017 and 2016, the fair value of the trust's funds was invested as follows: 56% and 54%, respectively, in domestic common equity securities, 34% and 35%, respectively, in United States government securities, 7% and 8%, respectively, in domestic corporate debt securities and 3% and 3%, respectively, in other securities.

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

(8) Short-Term Debt and Credit Facilities

Interim financing of working capital needs and the construction program is obtained from unaffiliated parties through the sale of commercial paper or short-term borrowing from banks. MidAmerican Energy has a $900 million unsecured credit facility expiring June 2020 with two one-year extension options subject to lender consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Eurodollar rate or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. In addition, MidAmerican Energy has a $5 million unsecured credit facility, which expires in June 2018 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2016, the weighted average interest rate on commercial paper borrowings outstanding was 0.73%. The $900 million credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter. As of December 31, 2017, MidAmerican Energy was in compliance with the covenants of its credit facilities. MidAmerican Energy has authority from the FERC to issue commercial paper and bank notes aggregating $905 million through February 28, 2019.

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

	2017	2016
Credit facilities	$ 905	$ 605
Less:		
Short-term debt outstanding	—	(99)
Variable-rate tax-exempt bond support	(370)	(220)
Net credit facilities	$ 535	$ 286

(9) Long-Term Debt

MidAmerican Energy's long-term debt consists of the following, including amounts maturing within one year and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2017	2016
First mortgage bonds:			
2.40%, due 2019	$ 500	$ 499	$ 499
3.70%, due 2023	250	248	248
3.50%, due 2024	500	501	501
3.10%, due 2027	375	372	—
4.80%, due 2043	350	346	345
4.40%, due 2044	400	394	394
4.25%, due 2046	450	445	445
3.95%, due 2047	475	470	—
Notes:			
5.95% Series, due 2017	—	—	250
5.3% Series, due 2018	350	350	350
6.75% Series, due 2031	400	396	396
5.75% Series, due 2035	300	298	298
5.8% Series, due 2036	350	347	347
Transmission upgrade obligation, 4.45% and 3.42% due through 2035 and 2036, respectively	8	6	7
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2017-1.91%, 2016-0.76%):			
Due 2023, issued in 1993	7	7	7
Due 2023, issued in 2008	57	57	57
Due 2024	35	35	35
Due 2025	13	13	13
Due 2036	33	33	33
Due 2038	45	45	45
Due 2046	30	29	29
Due 2047	150	149	—
Capital lease obligations - 4.16%, due through 2020	2	2	2
Total	$ 5,080	$ 5,042	$ 4,301

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2018, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2018	$ 350
2019	501
2020	2
2021	—
2022	—
2023 and thereafter	4,227

In February 2018, MidAmerican Energy issued $700 million of its 3.65% First Mortgage Bonds due August 2048.

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, 2017, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $16 billion based on original cost. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt bond obligations bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2017 and 2016. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with the $30 million and $150 million variable rate, tax-exempt bond obligations due 2046 and 2047, respectively, are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended. In December 2017, the Iowa Finance Authority issued $150 million of its variable-rate, tax-exempt Solid Waste Facilities Revenue Bonds due December 2047, the proceeds of which were loaned to MidAmerican Energy and restricted for the purpose of constructing solid waste facilities. As of December 31, 2017, $108 million of the restricted proceeds are reflected in other current assets on the Balance Sheet.

As of December 31, 2017, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2017, MidAmerican Energy's common equity ratio was 53% computed on a basis consistent with its commitment. As a result of its regulatory commitment to maintain its common equity level above certain thresholds, MidAmerican Energy could dividend $2.1 billion as of December 31, 2017, without falling below 42%.

(10) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018 and limitations on bonus depreciation for utility property. GAAP requires the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, MidAmerican Energy reduced deferred income tax liabilities $1,824 million. As it is probable the change in deferred taxes will be passed back to customers through regulatory mechanisms, MidAmerican Energy increased net regulatory liabilities by $1,845 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. MidAmerican Energy has recorded the impacts of 2017 Tax Reform and believes all the impacts to be complete with the exception of interpretations of the bonus depreciation rules. MidAmerican Energy has determined the amounts recorded and the interpretations relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. MidAmerican Energy believes its interpretations for bonus depreciation to be reasonable; however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

MidAmerican Energy's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2017	2016	2015
Current:			
Federal	$ (490)	$ (479)	$ (415)
State	(25)	(14)	(6)
	(515)	(493)	(421)
Deferred:			
Federal	335	366	281
State	(2)	(4)	(6)
	333	362	275
Investment tax credits	(1)	(1)	(1)
Total	$ (183)	$ (132)	$ (147)

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2017	2016	2015
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(68)	(61)	(71)
State income tax, net of federal income tax benefit	(4)	(3)	(2)
Effects of ratemaking	(7)	(3)	(12)
2017 Tax Reform	2	—	—
Other, net	(1)	—	1
Effective income tax rate	(43)%	(32)%	(49)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Interim recognition of production tax credits in income is based on the annualized effective tax rate applied each period, similar to all book to tax differences. Recognition of production tax credits in income during interim periods of the year may vary significantly from actual amounts earned. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 443	$ 333
Asset retirement obligations	160	230
Employee benefits	45	66
Other	57	74
Total deferred income tax assets	705	703
Deferred income tax liabilities:		
Depreciable property	(2,865)	(3,763)
Regulatory assets	(42)	(471)
Other	(35)	(41)
Total deferred income tax liabilities	(2,942)	(4,275)
Net deferred income tax liability	$ (2,237)	$ (3,572)

As of December 31, 2017, MidAmerican Energy has available $40 million of state tax carryforwards, principally related to $583 million of net operating losses, that expire at various intervals between 2018 and 2036.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 31, 2009, including components related to MidAmerican Energy. In addition, state jurisdictions have closed their examinations of MidAmerican Energy's income tax returns for Iowa through December 31, 2013, for Illinois through December 31, 2008, and for other jurisdictions through December 31, 2009.

A reconciliation of the beginning and ending balances of MidAmerican Energy's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2017	2016
Beginning balance	$ 10	$ 10
Additions based on tax positions related to the current year	1	—
Additions for tax positions of prior years	23	10
Reductions based on tax positions related to the current year	(4)	(2)
Reductions for tax positions of prior years	(19)	(8)
Interest and penalties	1	—
Ending balance	$ 12	$ 10

As of December 31, 2017, MidAmerican Energy had unrecognized tax benefits totaling $38 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Energy's effective income tax rate.

(11) Employee Benefit Plans

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering a majority of all employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and most union employees and final average pay formulas for other union employees. MidAmerican Energy also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans ("SERP") for certain active and retired participants.

MidAmerican Energy also sponsors certain postretirement healthcare and life insurance benefits covering substantially all retired employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Under the plans, a majority of all employees of the participating companies may become eligible for these benefits if they reach retirement age. New employees are not eligible for benefits under the plans. MidAmerican Energy has been allowed to recover accrued pension and other postretirement benefit costs in its electric and gas service rates.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns on equity investments over a five-year period beginning after the first year in which they occur.

MidAmerican Energy bills to and is reimbursed currently for affiliates' share of the net periodic benefit costs from all plans in which such affiliates participate. In 2017, 2016 and 2015, MidAmerican Energy's share of the pension net periodic benefit cost (credit) was $(6) million, $(2) million and $(4) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit cost (credit) in 2017, 2016 and 2015 totaled $(1) million, $(1) million and $- million, respectively.

Net periodic benefit cost for the plans of MidAmerican Energy and the aforementioned affiliates included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2017	2016	2015	2017	2016	2015
Service cost	$ 9	$ 10	$ 12	$ 5	$ 5	$ 7
Interest cost	31	34	32	9	10	9
Expected return on plan assets	(44)	(44)	(46)	(14)	(13)	(15)
Net amortization	2	2	2	(4)	(4)	(3)
Net periodic benefit (credit) cost	$ (2)	$ 2	$ —	$ (4)	$ (2)	$ (2)

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	
	2017	2016	2017	2016
Plan assets at fair value, beginning of year	$ 684	$ 678	$ 252	$ 249
Employer contributions	7	7	1	1
Participant contributions	—	—	1	1
Actual return on plan assets	114	57	36	14
Benefits paid	(60)	(58)	(13)	(13)
Plan assets at fair value, end of year	$ 745	$ 684	$ 277	$ 252

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

	Pension		Other Postretirement	
	2017	**2016**	**2017**	**2016**
Benefit obligation, beginning of year	$ 773	$ 785	$ 233	$ 234
Service cost	9	10	5	5
Interest cost	31	34	9	10
Participant contributions	—	—	1	1
Actuarial loss (gain)	46	2	11	(4)
Benefits paid	(60)	(58)	(13)	(13)
Benefit obligation, end of year	$ 799	$ 773	$ 246	$ 233
Accumulated benefit obligation, end of year	$ 790	$ 764		

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

	Pension		Other Postretirement	
	2017	**2016**	**2017**	**2016**
Plan assets at fair value, end of year	$ 745	$ 684	$ 277	$ 252
Less - Benefit obligation, end of year	799	773	246	233
Funded status	$ (54)	$ (89)	$ 31	$ 19
Amounts recognized on the Balance Sheets:				
Other assets	$ 66	$ 26	$ 31	$ 19
Other current liabilities	(8)	(8)	—	—
Other liabilities	(112)	(107)	—	—
Amounts recognized	$ (54)	$ (89)	$ 31	$ 19

The SERP has no plan assets; however, MidAmerican Energy has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $118 million and $110 million as of December 31, 2017 and 2016, respectively. These assets are not included in the plan assets in the above table, but are reflected in investments and restricted cash and investments on the Balance Sheets.

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2017	**2016**	**2017**	**2016**
Net (gain) loss	$ (11)	$ 15	$ 23	$ 36
Prior service cost (credit)	1	1	(25)	(31)
Total	$ (10)	$ 16	$ (2)	$ 5

MidAmerican Energy sponsors pension and other postretirement benefit plans on behalf of certain of its affiliates in addition to itself, and therefore, the portion of the funded status of the respective plans that has not yet been recognized in net periodic benefit cost is attributable to multiple entities. Additionally, substantially all of MidAmerican Energy's portion of such amounts is either refundable to or recoverable from its customers and is reflected as regulatory liabilities and regulatory assets.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2017 and 2016 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2015	$ 22	$ —	$ 6	$ 28
Net loss (gain) arising during the year	1	(11)	—	(10)
Net amortization	(1)	(1)	—	(2)
Total	—	(12)	—	(12)
Balance, December 31, 2016	22	(12)	6	16
Net loss (gain) arising during the year	4	(29)	1	(24)
Net amortization	(2)	—	—	(2)
Total	2	(29)	1	(26)
Balance, December 31, 2017	$ 24	$ (41)	$ 7	$ (10)

	Regulatory Asset	Receivables (Payables) with Affiliates	Total
Other Postretirement			
Balance, December 31, 2015	$ 17	$ (11)	$ 6
Net gain arising during the year	(2)	(3)	(5)
Net amortization	3	1	4
Total	1	(2)	(1)
Balance, December 31, 2016	18	(13)	5
Net gain arising during the year	(7)	(4)	(11)
Net amortization	3	1	4
Total	(4)	(3)	(7)
Balance, December 31, 2017	$ 14	$ (16)	$ (2)

The net loss and prior service cost (credit) that will be amortized in 2018 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Cost (Credit)	Total
Pension	$ 1	$ 1	$ 2
Other postretirement	1	(5)	(4)
Total	$ 2	$ (4)	$ (2)

Plan Assumptions

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

	Pension			Other Postretirement		
	2017	2016	2015	2017	2016	2015
Benefit obligations as of December 31:						
Discount rate	3.60%	4.10%	4.50%	3.50%	3.90%	4.25%
Rate of compensation increase	2.75%	2.75%	2.75%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.10%	4.50%	4.00%	3.90%	4.25%	3.75%
Expected return on plan assets(1)	6.75%	7.00%	7.25%	6.50%	6.75%	7.00%
Rate of compensation increase	2.75%	2.75%	2.75%	N/A	N/A	N/A

(1) Amounts reflected are pre-tax values. Assumed after-tax returns for a taxable, non-union other postretirement plan were 4.81% for 2017, and 5.00% for 2016, and 5.18% for 2015.

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

	2017	2016
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.10%	7.40%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2025

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

	One Percentage-Point	
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2017	$ —	$ —
Other postretirement benefit obligation as of December 31, 2017	3	(3)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $8 million and $1 million, respectively, during 2018. Funding to MidAmerican Energy's pension benefit plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. MidAmerican Energy considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. MidAmerican Energy's funding policy for its other postretirement benefit plan is to generally contribute amounts consistent with its rate regulatory arrangements.

Net periodic benefit costs assigned to MidAmerican Energy affiliates are reimbursed currently in accordance with its intercompany administrative services agreement. The expected benefit payments to participants in MidAmerican Energy's pension and other postretirement benefit plans for 2017 through 2021 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2018	$ 60	$ 19
2019	61	20
2020	60	21
2021	59	22
2022	57	21
2023-2027	256	98

Plan Assets

Investment Policy and Asset Allocations

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

The target allocations (percentage of plan assets) for MidAmerican Energy's pension and other postretirement benefit plan assets are as follows as of December 31, 2017:

	Pension	Other Postretirement
	%	%
Debt securities(1)	20-50	25-45
Equity securities(1)	60-80	45-80
Real estate funds	2-8	—
Other	0-3	0-5

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

Fair Value Measurements

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2017:				
Cash equivalents	$ —	$ 17	$ —	$ 17
Debt securities:				
United States government obligations	21	—	—	21
Corporate obligations	—	59	—	59
Municipal obligations	—	7	—	7
Agency, asset and mortgage-backed obligations	—	33	—	33
Equity securities:				
United States companies	137	—	—	137
International equity securities	44	—	—	44
Investment funds[2]	74	—	—	74
Total assets in the hierarchy	$ 276	$ 116	$ —	392
Investment funds[2] measured at net asset value				315
Real estate funds measured at net asset value				38
Total assets measured at fair value				$ 745
As of December 31, 2016:				
Cash equivalents	$ —	$ 17	$ —	$ 17
Debt securities:				
United States government obligations	9	—	—	9
Corporate obligations	—	53	—	53
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	22	—	22
Equity securities:				
United States companies	130	—	—	130
International equity securities	39	—	—	39
Investment funds[2]	63	—	—	63
Total assets in the hierarchy	$ 241	$ 98	$ —	339
Investment funds[2] measured at net asset value				295
Real estate funds measured at net asset value				50
Total assets measured at fair value				$ 684

(1) Refer to Note 14 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 69% and 31%, respectively, for 2017 and 74% and 26%, respectively, for 2016. Additionally, these funds are invested in United States and international securities of approximately 72% and 28%, respectively, for 2017 and 71% and 29%, respectively, for 2016.

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2017:				
Cash equivalents	$ 6	$ —	$ —	$ 6
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	14	—	14
Municipal obligations	—	44	—	44
Agency, asset and mortgage-backed obligations	—	12	—	12
Equity securities:				
United States companies	84	—	—	84
Investment funds[2]	112	—	—	112
Total assets measured at fair value	$ 207	$ 70	$ —	$ 277
As of December 31, 2016:				
Cash equivalents	$ 10	$ —	$ —	$ 10
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	11	—	11
Municipal obligations	—	37	—	37
Agency, asset and mortgage-backed obligations	—	11	—	11
Equity securities:				
United States companies	122	—	—	122
Investment funds[2]	56	—	—	56
Total assets measured at fair value	$ 193	$ 59	$ —	$ 252

(1) Refer to Note 14 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 81% and 19%, respectively, for 2017 and 70% and 30%, respectively, for 2016. Additionally, these funds are invested in United States and international securities of approximately 42% and 58%, respectively, for 2017 and 30% and 70%, respectively, for 2016.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

MidAmerican Energy sponsors a defined contribution plan ("401(k) plan") covering substantially all employees. MidAmerican Energy's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the 401(k) plan and no longer accrue benefits in the noncontributory defined benefit pension plans. MidAmerican Energy's contributions to the plan were $20 million, $20 million, and $20 million for the years ended December 31, 2017, 2016 and 2015, respectively.

(12) Asset Retirement Obligations

MidAmerican Energy estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

MidAmerican Energy does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $688 million and $665 million as of December 31, 2017 and 2016, respectively.

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

	2017	2016
Quad Cities Station	$ 342	$ 343
Fossil-fueled generating facilities	113	132
Wind-powered generating facilities	103	91
Other	1	1
Total asset retirement obligations	$ 559	$ 567
Quad Cities Station nuclear decommissioning trust funds[1]	$ 515	$ 460

(1) Refer to Note 7 for a discussion of the Quad Cities Station nuclear decommissioning trust funds.

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

	2017	2016
Beginning balance	$ 567	$ 532
Change in estimated costs	(14)	28
Additions	8	14
Retirements	(26)	(32)
Accretion	24	25
Ending balance	$ 559	$ 567
Reflected as:		
Other current liabilities	$ 31	$ 57
Asset retirement obligations	528	510
	$ 559	$ 567

The changes in estimated costs for 2017 and 2016 were primarily due to new decommissioning studies conducted by the operator of Quad Cities Station that changed the estimated amount and timing of cash flows.

(13) Risk Management and Hedging Activities

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. Prior to January 1, 2016, MidAmerican Energy also provided nonregulated retail electricity and natural gas services in competitive markets, which created contractual obligations to provide electric and natural gas services. MidAmerican Energy's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. MidAmerican Energy does not engage in a material amount of proprietary trading activities.

MidAmerican Energy has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. MidAmerican Energy manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, MidAmerican Energy may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate its exposure to interest rate risk. MidAmerican Energy does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in MidAmerican Energy's accounting policies related to derivatives. Refer to Notes 2 and 14 for additional information on derivative contracts and to Note 3 for a discussion of discontinued operations.

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

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2017:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 6	$ —	$ 1	$ —	$ 7
Commodity liabilities	(1)	—	(7)	(2)	(10)
Total derivatives	5	—	(6)	(2)	(3)
Cash collateral receivable	—	—	—	—	—
Total derivatives - net basis	$ 5	$ —	$ (6)	$ (2)	$ (3)
As of December 31, 2016:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 8	$ 2	$ —	$ —	$ 10
Commodity liabilities	(2)	—	(3)	(1)	(6)
Total derivatives	6	2	(3)	(1)	4
Cash collateral receivable	—	—	1	—	1
Total derivatives - net basis	$ 6	$ 2	$ (2)	$ (1)	$ 5

(1) MidAmerican Energy's commodity derivatives not designated as hedging contracts are generally included in regulated rates. Accordingly, as of December 31, 2017, a net regulatory asset of $3 million was recorded related to the net derivative a liability of $3 million, and as of December 31, 2016, a net regulatory liability of $(4) million was recorded related to the net derivative asset of $4 million.

Not Designated as Hedging Contracts

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

	2017	2016	2015
Beginning balance	$ (4)	$ 20	$ 38
Changes in fair value recognized in net regulatory assets (liabilities)	16	3	40
Net gains (losses) reclassified to operating revenue	1	(15)	(42)
Net losses reclassified to cost of fuel, energy and capacity	(4)	—	(1)
Net losses reclassified to cost of gas sold	(6)	(12)	(15)
Ending balance	$ 3	$ (4)	$ 20

The following table summarizes the pre-tax unrealized gains (losses) included on the Statements of Operations associated with MidAmerican Energy's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability for the years ended December 31 (in millions):

	2017	2016	2015
Nonregulated operating revenue	$ —	$ —	$ 15
Regulated cost of fuel, energy and capacity	—	—	2
Nonregulated cost of sales	—	—	(21)
Total	$ —	$ —	$ (4)

Designated as Hedging Contracts

MidAmerican Energy used derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices related to its unregulated retail services business, which was transferred to a subsidiary of BHE. The following table reconciles the beginning and ending balances of MidAmerican Energy's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings, for the years ended December 31 (in millions):

	2017	2016	2015
Beginning balance	$ —	$ 45	$ 34
Transfer to affiliate	—	(45)	—
Changes in fair value recognized in OCI	—	—	58
Net losses reclassified to nonregulated cost of sales	—	—	(47)
Ending balance	$ —	$ —	$ 45

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	2017	2016
Natural gas purchases	Decatherms	21	18

Credit Risk

MidAmerican Energy is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Additionally, MidAmerican Energy participates in the regional transmission organization ("RTO") markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MidAmerican Energy enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MidAmerican Energy exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base MidAmerican Energy's collateral requirements on its credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, MidAmerican Energy's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of MidAmerican Energy's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $8 million and $3 million as of December 31, 2017 and 2016, respectively, for which MidAmerican Energy had posted collateral of $- million at each date. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2017 and 2016, MidAmerican Energy would have been required to post $- million and $2 million, respectively, of additional collateral. MidAmerican Energy's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. MidAmerican Energy's exposure to contingent features declined significantly as a result of the transfer of its unregulated retail services business to a subsidiary of BHE.

(14) Fair Value Measurements

The carrying value of MidAmerican Energy's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. MidAmerican Energy has various financial assets and liabilities that are measured at fair value on the Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that MidAmerican Energy has the ability to access at the measurement date.

- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

- Level 3 - Unobservable inputs reflect MidAmerican Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. MidAmerican Energy develops these inputs based on the best information available, including its own data.

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

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other(1)	Total
As of December 31, 2017:					
Assets:					
Commodity derivatives	$ —	$ 3	$ 4	$ (2)	$ 5
Money market mutual funds(2)	133	—	—	—	133
Debt securities:					
United States government obligations	176	—	—	—	176
International government obligations	—	5	—	—	5
Corporate obligations	—	36	—	—	36
Municipal obligations	—	2	—	—	2
Equity securities:					
United States companies	288	—	—	—	288
International companies	7	—	—	—	7
Investment funds	15	—	—	—	15
	$ 619	$ 46	$ 4	$ (2)	$ 667
Liabilities - commodity derivatives	$ —	$ (9)	$ (1)	$ 2	$ (8)
As of December 31, 2016					
Assets:					
Commodity derivatives	$ —	$ 9	$ 1	$ (2)	$ 8
Money market mutual funds(2)	1	—	—	—	1
Debt securities:					
United States government obligations	161	—	—	—	161
International government obligations	—	3	—	—	3
Corporate obligations	—	36	—	—	36
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
United States companies	250	—	—	—	250
International companies	5	—	—	—	5
Investment funds	9	—	—	—	9
	$ 426	$ 52	$ 1	$ (2)	$ 477
Liabilities - commodity derivatives	$ —	$ (3)	$ (3)	$ 3	$ (3)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $- million and $1 million as of December 31, 2017 and 2016, respectively.

(2) Amounts are included in cash and cash equivalents and investments and restricted cash and investments on the Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which MidAmerican Energy transacts. When quoted prices for identical contracts are not available, MidAmerican Energy uses forward price curves. Forward price curves represent MidAmerican Energy's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. MidAmerican Energy bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by MidAmerican Energy. Market price quotations are generally readily obtainable for the applicable term of MidAmerican Energy's outstanding derivative contracts; therefore, MidAmerican Energy's forward price curves reflect observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, MidAmerican Energy uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 13 for further discussion regarding MidAmerican Energy's risk management and hedging activities.

MidAmerican Energy's investments in money market mutual funds and debt and equity securities are stated at fair value and are 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 following table reconciles the beginning and ending balances of MidAmerican Energy's assets measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	Commodity Derivatives			Auction Rate Securities		
	2017	2016	2015	2017	2016	2015
Beginning balance	$ (2)	$ (6)	$ 12	$ —	$ 26	$ 26
Transfer to affiliate	—	(4)	—	—	—	—
Changes included in earnings[1]	—	—	11	—	5	—
Changes in fair value recognized in OCI	—	—	(7)	—	4	—
Changes in fair value recognized in net regulatory assets	2	(6)	(25)	—	—	—
Purchases	—	—	1	—	—	—
Redemptions	—	—	—	—	(35)	—
Settlements	3	14	2	—	—	—
Ending balance	$ 3	$ (2)	$ (6)	$ —	$ —	$ 26

(1) Changes included in earnings related to MidAmerican Energy's unregulated retail services business that was transferred to an affiliate of BHE. Refer to Note 3 for a discussion of discontinued operations. Net unrealized gains included in earnings for the year ended December 31, 2015, related to commodity derivatives held at December 31, 2015, totaled $8 million.

MidAmerican Energy's long-term debt is carried at cost on the Financial Statements. The fair value of MidAmerican Energy's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of MidAmerican Energy's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of MidAmerican Energy's long-term debt as of December 31 (in millions):

	2017		2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 5,042	$ 5,686	$ 4,301	$ 4,735

(15) Commitments and Contingencies

Commitments

MidAmerican Energy had the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2017, are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 112	$ 56	$ 12	$ 9	$ 8	$ —	$ 197
Electric capacity and transmission	34	31	31	27	16	43	182
Natural gas contracts for gas operations	122	75	73	57	42	42	411
Construction commitments	790	28	2	—	—	—	820
Easements and operating leases	22	21	21	21	21	713	819
Maintenance and services contracts	96	102	119	114	154	233	818
	$ 1,176	$ 313	$ 258	$ 228	$ 241	$ 1,031	$ 3,247

Coal, Natural Gas, Electric Capacity and Transmission Commitments

MidAmerican Energy has coal supply and related transportation and lime contracts for its coal-fueled generating facilities. MidAmerican Energy expects to supplement the coal contracts with additional contracts and spot market purchases to fulfill its future coal supply needs. Additionally, MidAmerican Energy has a natural gas transportation contract for a natural gas-fueled generating facility. The contracts have minimum payment commitments ranging through 2022.

MidAmerican Energy has various natural gas supply and transportation contracts for its regulated and nonregulated gas operations that have minimum payment commitments ranging through 2037.

MidAmerican Energy has contracts to purchase electric capacity that have minimum payment commitments ranging through 2028. MidAmerican Energy also has contracts for the right to transmit electricity over other entities' transmission lines with minimum payment commitments ranging through 2022.

Construction Commitments

MidAmerican Energy's firm construction commitments reflected in the table above consist primarily of contracts for the construction of wind-powered generating facilities in 2018, the settlement of asset retirement obligations for ash pond closures and the construction in 2018 of the last of four Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois.

Easements and Operating Leases

MidAmerican Energy has non-cancelable easements with minimum payment commitments ranging through 2061 for land in Iowa on which certain of its assets, primarily wind-powered generating facilities, are located. MidAmerican Energy also has non-cancelable operating leases with minimum payment commitments ranging through 2020 primarily for office and other building space, rail cars and computer equipment. These leases generally require MidAmerican Energy to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Rent expense on non-cancelable operating leases totaled $3 million, $4 million and $4 million for 2017, 2016 and 2015, respectively.

Maintenance and Services Contracts

MidAmerican Energy has non-cancelable maintenance and services contracts related to various generating facilities with minimum payment commitments ranging through 2027.

Environmental Laws and Regulations

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

Transmission Rates

MidAmerican Energy's wholesale transmission rates are set annually using FERC-approved formula rates subject to true-up for actual cost of service. Prior to September 2016, the rates in effect were based on a 12.38% return on equity ("ROE"). In November 2013 and February 2015, a coalition of intervenors filed successive complaints with the FERC requesting that the 12.38% ROE no longer be found just and reasonable and sought to reduce the base ROE to 9.15% and 8.67%, respectively. MidAmerican Energy is authorized by the FERC to include a 0.50% adder beyond the base ROE effective January 2015. In September 2016, the FERC issued an order for the first complaint, which reduces the base ROE to 10.32% and requires refunds, plus interest, for the period from November 2013 through February 2015. It is uncertain when the FERC will rule on the second complaint, covering the period from February 2015 through May 2016. MidAmerican Energy believes it is probable that the FERC will order a base ROE lower than 12.38% in the second complaint and, as of December 31, 2017, has accrued a $9 million liability for refunds of amounts collected under the higher ROE from November 2013 through May 2016.

Legal Matters

MidAmerican Energy is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MidAmerican Energy does not believe that such normal and routine litigation will have a material impact on its financial results.

(16) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss by each component of other comprehensive income, net of applicable income taxes, for the year ended December 31, 2016 (in millions):

	Unrealized Losses on Available-For-Sale Securities	Unrealized Losses on Cash Flow Hedges	Accumulated Other Comprehensive Loss, Net
Balance, December 31, 2015	$ (3)	$ (27)	$ (30)
Other comprehensive income	3	—	3
Dividend (Note 3)	—	27	27
Balance, December 31, 2016	$ —	$ —	$ —

For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety for the years ended December 31, 2016 and 2015, refer to Note 13.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2017	2016	2015
Corporate-owned life insurance income	$ 13	$ 8	$ 4
Gain on redemption of auction rate securities	—	5	—
Interest income and other, net	6	1	1
Total	$ 19	$ 14	$ 5

(18) Supplemental Cash Flow Disclosures

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

	2017	2016	2015
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 193	$ 181	$ 154
Income taxes received, net	$ 465	$ 601	$ 629
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 224	$ 131	$ 249
Dividend of unregulated retail services business (Note 3)	$ —	$ 90	$ —

(19) Related Party Transactions

The companies identified as affiliates of MidAmerican Energy are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Energy and the affiliates.

MidAmerican Energy is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for general costs, such as insurance and building rent, and for employee wages, benefits and costs related to corporate functions such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $53 million, $41 million and $46 million for 2017, 2016 and 2015, respectively.

MidAmerican Energy reimbursed BHE in the amount of $9 million, $6 million and $7 million in 2017, 2016 and 2015, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $122 million, $135 million and $165 million in 2017, 2016 and 2015, respectively.

MidAmerican Energy had accounts receivable from affiliates of $9 million and $5 million as of December 31, 2017 and 2016, respectively, that are included in receivables on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $16 million and $13 million as of December 31, 2017 and 2016, respectively, that are included in accounts payable on the Balance Sheets.

MidAmerican Energy is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated United States federal income tax return. For current federal and state income taxes, MidAmerican Energy had a receivable from BHE of $51 million as of December 31, 2017, and a payable to BHE of $6 million as of December 31, 2016. MidAmerican Energy received net cash receipts for federal and state income taxes from BHE totaling $465 million, $601 million and $629 million for the years ended December 31, 2017, 2016 and 2015, respectively.

MidAmerican Energy recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Energy's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Energy adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $16 million and $12 million as of December 31, 2017 and 2016, respectively, and similar amounts payable to affiliates totaled $45 million and $36 million as of December 31, 2017 and 2016, respectively. See Note 11 for further information pertaining to pension and postretirement accounting.

(20) Segment Information

MidAmerican Energy has identified two reportable operating segments: regulated electric and regulated gas. The previously reported nonregulated energy segment consisted substantially of MidAmerican Energy's unregulated retail services business, which was transferred to a subsidiary of BHE and is excluded from the information below related to the statements of operations for all periods presented. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. Refer to Note 10 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2017	2016	2015
Operating revenue:			
Regulated electric	$ 2,108	$ 1,985	$ 1,837
Regulated gas	719	637	661
Other	10	3	4
Total operating revenue	$ 2,837	$ 2,625	$ 2,502
Depreciation and amortization:			
Regulated electric	$ 458	$ 436	$ 366
Regulated gas	42	43	41
Total depreciation and amortization	$ 500	$ 479	$ 407
Operating income:			
Regulated electric	$ 485	$ 497	$ 385
Regulated gas	77	68	64
Other	(1)	—	—
Total operating income	$ 561	$ 565	$ 449
Interest expense:			
Regulated electric	$ 196	$ 178	$ 166
Regulated gas	18	18	17
Total interest expense	$ 214	$ 196	$ 183
Income tax (benefit) expense from continuing operations:			
Regulated electric	$ (212)	$ (156)	$ (163)
Regulated gas	29	22	16
Other	—	2	—
Total income tax (benefit) expense from continuing operations	$ (183)	$ (132)	$ (147)
Net income:			
Regulated electric	$ 570	$ 512	$ 413
Regulated gas	35	32	33
Other	—	(2)	—
Income from continuing operations	605	542	446
Income on discontinued operations	—	—	16
Net income	$ 605	$ 542	$ 462

	Years Ended December 31,		
	2017	2016	2015
Utility construction expenditures:			
Regulated electric	$ 1,686	$ 1,564	$ 1,365
Regulated gas	87	72	81
Total utility construction expenditures	$ 1,773	$ 1,636	$ 1,446

	As of December 31,		
	2017	2016	2015
Total assets:			
Regulated electric	$ 14,914	$ 14,113	$ 12,970
Regulated gas	1,403	1,345	1,251
Other	1	1	164
Total assets	$ 16,318	$ 15,459	$ 14,385

(21) Unaudited Quarterly Operating Results

	2017			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 695	$ 658	$ 813	$ 671
Operating income	107	135	288	31
Net income (loss)	105	134	385	(19)

	2016			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 625	$ 584	$ 795	$ 621
Operating income	100	139	284	42
Net income	76	131	320	15

Quarterly operating results are affected by, among other things, MidAmerican Energy's seasonal retail electricity prices, the timing of recognition of federal renewable electricity production tax credits related to MidAmerican Energy's wind-powered generating facilities and the seasonal impact of weather on electricity and natural gas sales.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Member of
MidAmerican Funding, LLC
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MidAmerican Funding, LLC and subsidiaries ("MidAmerican Funding") as of December 31, 2017 and 2016, 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, 2017, and the related notes and the schedules listed in the Index at Item 15(a)(ii) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of MidAmerican Funding as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MidAmerican Funding's management. Our responsibility is to express an opinion on MidAmerican Funding's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to MidAmerican Funding in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. MidAmerican Funding is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Funding’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 23, 2018

We have served as MidAmerican Funding's auditor since 1999.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2017	**2016**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 172	$ 15
Receivables, net	348	287
Income taxes receivable	64	9
Inventories	245	264
Other current assets	134	35
Total current assets	963	610
Property, plant and equipment, net	14,221	12,835
Goodwill	1,270	1,270
Regulatory assets	204	1,161
Investments and restricted cash and investments	730	655
Other assets	233	216
Total assets	$ 17,621	$ 16,747

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2017	**2016**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 451	$ 302
Accrued interest	53	52
Accrued property, income and other taxes	133	138
Note payable to affiliate	164	31
Short-term debt	—	99
Current portion of long-term debt	350	250
Other current liabilities	128	160
Total current liabilities	1,279	1,032
Long-term debt	4,932	4,377
Deferred income taxes	2,235	3,568
Regulatory liabilities	1,661	883
Asset retirement obligations	528	510
Other long-term liabilities	326	291
Total liabilities	10,961	10,661
Commitments and contingencies (Note 15)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	4,981	4,407
Total member's equity	6,660	6,086
Total liabilities and member's equity	$ 17,621	$ 16,747

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	2016	2015
Operating revenue:			
Regulated electric	$ 2,108	$ 1,985	$ 1,837
Regulated gas and other	738	646	678
Total operating revenue	2,846	2,631	2,515
Operating costs and expenses:			
Cost of fuel, energy and capacity	434	409	433
Cost of gas sold and other	447	371	407
Operations and maintenance	784	694	707
Depreciation and amortization	500	479	407
Property and other taxes	119	112	110
Total operating costs and expenses	2,284	2,065	2,064
Operating income	562	566	451
Other income and (expense):			
Interest expense	(237)	(219)	(206)
Allowance for borrowed funds	15	8	8
Allowance for equity funds	41	19	20
Other, net	(9)	19	19
Total other income and (expense)	(190)	(173)	(159)
Income before income tax benefit	372	393	292
Income tax benefit	(202)	(139)	(150)
Income from continuing operations	574	532	442
Discontinued operations (Note 3):			
Income from discontinued operations	—	—	22
Income tax expense	—	—	6
Income on discontinued operations	—	—	16
Net income	$ 574	$ 532	$ 458

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2017	2016	2015
Net income	$ 574	$ 532	$ 458
Other comprehensive income (loss), net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $-, $1 and $-	—	3	—
Unrealized losses on cash flow hedges, net of tax of $-, $- and $(4)	—	—	(7)
Total other comprehensive income (loss), net of tax	—	3	(7)
Comprehensive income	$ 574	$ 535	$ 451

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Equity
Balance, December 31, 2014	$ 1,679	$ 3,417	$ (23)	$ 5,073
Net income	—	458	—	458
Other comprehensive loss	—	—	(7)	(7)
Other equity transactions	—	1	—	1
Balance, December 31, 2015	1,679	3,876	(30)	5,525
Net income	—	532	—	532
Other comprehensive income	—	—	3	3
Transfer to affiliate (Note 3)	—	—	27	27
Other equity transactions	—	(1)	—	(1)
Balance, December 31, 2016	1,679	4,407	—	6,086
Net income	—	574	—	574
Balance, December 31, 2017	$ 1,679	$ 4,981	$ —	$ 6,660

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 574	$ 532	$ 458
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss on other items	29	—	—
Depreciation and amortization	500	479	407
Deferred income taxes and amortization of investment tax credits	334	362	276
Changes in other assets and liabilities	37	47	49
Other, net	(58)	(92)	(69)
Changes in other operating assets and liabilities:			
Receivables, net	(60)	(61)	93
Inventories	19	(27)	(53)
Derivative collateral, net	2	5	33
Pension and other postretirement benefit plans, net	(11)	(6)	(8)
Accounts payable	69	39	(76)
Accrued property, income and other taxes, net	(54)	107	213
Other current assets and liabilities	(1)	8	12
Net cash flows from operating activities	1,380	1,393	1,335
Cash flows from investing activities:			
Utility construction expenditures	(1,773)	(1,636)	(1,446)
Purchases of available-for-sale securities	(143)	(138)	(142)
Proceeds from sales of available-for-sale securities	137	158	135
Proceeds from sales of other investments	2	2	13
Net increase in restricted cash and short-term investments	(98)	(10)	—
Other, net	(2)	10	2
Net cash flows from investing activities	(1,877)	(1,614)	(1,438)
Cash flows from financing activities:			
Proceeds from long-term debt	990	62	649
Repayments of long-term debt	(341)	(38)	(426)
Net change in note payable to affiliate	133	9	3
Net (repayments of) proceeds from short-term debt	(99)	99	(50)
Tender offer premium paid	(29)	—	—
Other, net	—	1	—
Net cash flows from financing activities	654	133	176
Net change in cash and cash equivalents	157	(88)	73
Cash and cash equivalents at beginning of year	15	103	30
Cash and cash equivalents at end of year	$ 172	$ 15	$ 103

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

(1) Company Organization

MidAmerican Funding, LLC ("MidAmerican Funding") is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MidAmerican Funding's direct wholly owned subsidiary is MHC Inc. ("MHC"), which constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations. Direct, wholly owned nonregulated subsidiaries of MHC are Midwest Capital Group, Inc. ("Midwest Capital Group") and MEC Construction Services Co.

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements for significant accounting policies of MidAmerican Funding.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MidAmerican Funding and its subsidiaries in which it held a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, MidAmerican Funding estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2017, 2016 and 2015, MidAmerican Funding did not record any goodwill impairments.

(3) Discontinued Operations

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. The transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE repaid $117 million of MHC's note payable to BHE.

(4) Property, Plant and Equipment, Net

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MidAmerican Funding had nonregulated property gross of $24 million and $22 million as of December 31, 2017 and 2016, respectively, related accumulated depreciation and amortization of $10 million and $9 million as of December 31, 2017 and 2016, respectively, and construction work-in-progress of $1 million as of December 31, 2016, which consisted primarily of a corporate aircraft owned by MHC.

(5) Jointly Owned Utility Facilities

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements.

(6) Regulatory Matters

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements.

(7) Investments and Restricted Cash and Investments

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted cash and investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2017 and 2016.

(8) Short-Term Debt and Credit Facilities

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2018 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2017 and 2016, there were no borrowings outstanding under this credit facility. As of December 31, 2017, MHC was in compliance with the covenants of its credit facility.

(9) Long-Term Debt

Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements for detail and a discussion of its long-term debt. In addition to MidAmerican Energy's annual repayments of long-term debt, MidAmerican Funding has $239 million of 6.927% Senior Bonds due in 2029, with a carrying value of $240 million and $326 million as of December 31, 2017 and 2016, respectively. In December 2017, MidAmerican Funding redeemed through a tender offer a portion of its 6.927% Senior Bonds. A charge of $29 million for the total premium is included in other income and (expense), net on the Consolidated Statement of Operations.

MidAmerican Funding parent company long-term debt is secured by a pledge of the common stock of MHC. See Item 15(c) for the Consolidated Financial Statements of MHC Inc. and subsidiaries. The bonds are the direct senior secured obligations of MidAmerican Funding and effectively rank junior to all indebtedness and other liabilities of the direct and indirect subsidiaries of MidAmerican Funding, to the extent of the assets of these subsidiaries. MidAmerican Funding may redeem the bonds in whole or in part at any time at a redemption price equal to the sum of any accrued and unpaid interest to the date of redemption and the greater of (1) 100% of the principal amount of the bonds or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the bonds, discounted to the date of redemption on a semiannual basis at the treasury yield plus 25 basis points.

Subsidiaries of MidAmerican Funding must make payments on their own indebtedness before making distributions to MidAmerican Funding. Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements for a discussion of utility regulatory restrictions affecting distributions from MidAmerican Energy. As a result of the utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, MidAmerican Funding had restricted net assets of $3.7 billion as of December 31, 2017.

As of December 31, 2017, MidAmerican Funding was in compliance with all of its applicable long-term debt covenants.

Each of MidAmerican Funding's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Funding and its other subsidiaries. It should not be assumed that any asset of any subsidiary of MidAmerican Funding will be available to satisfy the obligations of MidAmerican Funding or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MidAmerican Funding, one of its subsidiaries or affiliates thereof.

(10) Income Taxes

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law, which impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018 and limitations on bonus depreciation for utility property. Accounting principles generally accepted in the United States of America ("GAAP") require the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, MidAmerican Funding reduced deferred income tax liabilities $1,822 million. As it is probable the change in deferred taxes for the MidAmerican Funding's regulated businesses will be passed back to customers through regulatory mechanisms, MidAmerican Funding increased net regulatory liabilities by $1,845 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. MidAmerican Funding has recorded the impacts of 2017 Tax Reform and believes all the impacts to be complete with the exception of interpretations of the bonus depreciation rules. MidAmerican Funding has determined the amounts recorded and the interpretations relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. MidAmerican Funding believes its interpretations for bonus depreciation to be reasonable; however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

MidAmerican Funding's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2017	2016	2015
Current:			
Federal	$ (505)	$ (485)	$ (418)
State	(31)	(16)	(8)
	(536)	(501)	(426)
Deferred:			
Federal	338	367	282
State	(3)	(4)	(5)
	335	363	277
Investment tax credits	(1)	(1)	(1)
Total	$ (202)	$ (139)	$ (150)

A reconciliation of the federal statutory income tax rate MidAmerican Funding's the effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2017	2016	2015
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(77)	(64)	(72)
State income tax, net of federal income tax benefit	(6)	(3)	(3)
Effects of ratemaking	(8)	(3)	(12)
2017 Tax Reform	3	—	—
Other, net	(1)	—	1
Effective income tax rate	(54)%	(35)%	(51)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Interim recognition of production tax credits in income is based on the annualized effective tax rate applied each period, similar to all book to tax differences. Recognition of production tax credits in income during interim periods of the year may vary significantly from actual amounts earned. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 443	$ 333
Employee benefits	45	66
Asset retirement obligations	160	230
Other	62	82
Total deferred income tax assets	710	711
Deferred income tax liabilities:		
Depreciable property	(2,868)	(3,767)
Regulatory assets	(42)	(471)
Other	(35)	(41)
Total deferred income tax liabilities	(2,945)	(4,279)
Net deferred income tax liability	$ (2,235)	$ (3,568)

As of December 31, 2017, MidAmerican Funding has available $40 million of state tax carryforwards, principally related to $583 million of net operating losses, that expire at various intervals between 2018 and 2036.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 31, 2009, including components related to MidAmerican Funding. In addition, state jurisdictions have closed their examinations of MidAmerican Funding's income tax returns for Iowa through December 31, 2013, for Illinois through December 31, 2008, and for other jurisdictions through December 31, 2009.

A reconciliation of the beginning and ending balances of MidAmerican Funding's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2017	2016
Beginning balance	$ 10	$ 10
Additions based on tax positions related to the current year	1	—
Additions for tax positions of prior years	23	10
Reductions based on tax positions related to the current year	(4)	(2)
Reductions for tax positions of prior years	(19)	(8)
Interest and penalties	1	—
Ending balance	$ 12	$ 10

As of December 31, 2017, MidAmerican Funding had unrecognized tax benefits totaling $39 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Funding's effective income tax rate.

(11) Employee Benefit Plans

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements for additional information regarding MidAmerican Funding's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MidAmerican Funding to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2017	2016	2015
Pension costs	$ 4	$ 4	$ 4
Other postretirement costs	(3)	(1)	(2)

(12) Asset Retirement Obligations

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements.

(13) Risk Management and Hedging Activities

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements.

(14) Fair Value Measurements

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements.

MidAmerican Funding's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of MidAmerican Funding's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of MidAmerican Funding's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of MidAmerican Funding's long-term debt as of December 31 (in millions):

	2017		2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 5,282	$ 6,006	$ 4,627	$ 5,164

(15) Commitments and Contingencies

Refer to Note 15 of MidAmerican Energy's Notes to Financial Statements.

Legal Matters

MidAmerican Funding is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MidAmerican Funding does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(16) Components of Accumulated Other Comprehensive Loss, Net

Refer to Note 16 of MidAmerican Energy's Notes to Financial Statements.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2017	2016	2015
Corporate-owned life insurance income	$ 13	$ 8	$ 4
Gain on redemption of auction rate securities	—	5	—
Gains on sales of assets and other investments	1	3	13
Loss on debt tender offer	(29)	—	—
Interest income and other, net	6	3	2
Total	$ (9)	$ 19	$ 19

Refer to Note 9 for information regarding the debt tender offer. MidAmerican Funding recognized a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

(18) Supplemental Cash Flow Information

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

	2017	2016	2015
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 218	$ 204	$ 177
Income taxes received, net	$ 472	$ 609	$ 630
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 224	$ 131	$ 249
Transfer of assets and liabilities to affiliate (Note 3)	$ —	$ 90	$ —

(19) Related Party Transactions

The companies identified as affiliates of MidAmerican Funding are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Funding and the affiliates.

MidAmerican Funding is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $46 million, $35 million and $35 million for 2017, 2016 and 2015, respectively.

MidAmerican Funding reimbursed BHE in the amount of $9 million, $6 million and $7 million in 2017, 2016 and 2015, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $122 million, $135 million and $165 million in 2017, 2016 and 2015, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $164 million at an interest rate of 1.629% as of December 31, 2017, and $31 million at an interest rate of 0.885% as of December 31, 2016, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement, carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2017 and 2016.

MidAmerican Funding had accounts receivable from affiliates of $9 million and $7 million as of December 31, 2017 and 2016, respectively, that are included in receivables, net on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $14 million and $12 million as of December 31, 2017 and 2016, respectively, that are included in accounts payable on the Consolidated Balance Sheets.

MidAmerican Funding is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated United States federal income tax return. For current federal and state income taxes, MidAmerican Funding had a receivable from BHE of $64 million as of December 31, 2017, and a payable to BHE of $7 million as of December 31, 2016. MidAmerican Funding received net cash receipts for federal and state income taxes from BHE totaling $472 million, $609 million and $631 million for the years ended December 31, 2017, 2016 and 2015, respectively.

MidAmerican Funding recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Funding's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Funding adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $16 million and $12 million as of December 31, 2017 and 2016, respectively, and similar amounts payable to affiliates totaled $45 million and $36 million as of December 31, 2017 and 2016, respectively. See Note 11 for further information pertaining to pension and postretirement accounting.

The indenture pertaining to MidAmerican Funding's long-term debt restricts MidAmerican Funding from paying a distribution on its equity securities, unless after making such distribution either its debt to total capital ratio does not exceed 0.67:1 and its interest coverage ratio is not less than 2.2:1 or its senior secured long-term debt rating is at least BBB or its equivalent. MidAmerican Funding may seek a release from this restriction upon delivery to the indenture trustee of written confirmation from the ratings agencies that without this restriction MidAmerican Funding's senior secured long-term debt would be rated at least BBB+.

(20) Segment Information

MidAmerican Funding has identified two reportable operating segments: regulated electric and regulated gas. The previously reported nonregulated energy segment consisted substantially of MidAmerican Energy's unregulated retail services business, which was transferred to a subsidiary of BHE and is excluded from the information below related to the statements of operations for all periods presented. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business and parent company interest expense. Refer to Note 10 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2017	2016	2015
Operating revenue:			
Regulated electric	$ 2,108	$ 1,985	$ 1,837
Regulated gas	719	637	661
Other	19	9	17
Total operating revenue	$ 2,846	$ 2,631	$ 2,515
Depreciation and amortization:			
Regulated electric	$ 458	$ 436	$ 366
Regulated gas	42	43	41
Total depreciation and amortization	$ 500	$ 479	$ 407
Operating income:			
Regulated electric	$ 485	$ 497	$ 385
Regulated gas	77	68	64
Other	—	1	2
Total operating income	$ 562	$ 566	$ 451
Interest expense:			
Regulated electric	$ 196	$ 178	$ 166
Regulated gas	18	18	17
Other	23	23	23
Total interest expense	$ 237	$ 219	$ 206
Income tax (benefit) expense from continuing operations:			
Regulated electric	$ (212)	$ (156)	$ (163)
Regulated gas	29	22	16
Other	(19)	(5)	(3)
Total income tax (benefit) expense from continuing operations	$ (202)	$ (139)	$ (150)
Net income:			
Regulated electric	$ 570	$ 512	$ 413
Regulated gas	35	32	33
Other	(31)	(12)	(4)
Income from continuing operations	574	532	442
Income on discontinued operations	—	—	16
Net income	$ 574	$ 532	$ 458
Utility construction expenditures:			
Regulated electric	$ 1,686	$ 1,564	$ 1,365
Regulated gas	87	72	81
Total utility construction expenditures	$ 1,773	$ 1,636	$ 1,446

	As of December 31,		
	2017	2016	2015
Total assets:			
Regulated electric	$ 16,105	$ 15,304	$ 14,161
Regulated gas	1,482	1,424	1,330
Other	34	19	183
Total assets	$ 17,621	$ 16,747	$ 15,674

Goodwill by reportable segment as of December 31, 2017 and 2016, was as follows (in millions):

Regulated electric	$ 1,191
Regulated gas	79
Total	$ 1,270

(21) Unaudited Quarterly Operating Results

	2017			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 696	$ 659	$ 815	$ 676
Operating income	107	136	288	31
Net income (loss)	102	131	383	(42)

	2016			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 626	$ 585	$ 797	$ 623
Operating income	100	140	284	42
Net income	73	127	318	14

Quarterly operating results are affected by, among other things, MidAmerican Energy's seasonal retail electricity prices, the timing of recognition of federal renewable electricity production tax credits related to MidAmerican Energy's wind-powered generating facilities and the seasonal impact of weather on electricity and natural gas sales.

Nevada Power Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

Nevada Power's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy and resources. Nevada Power is a summer peaking utility experiencing its highest retail energy sales in response to the demand for air conditioning. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of Nevada Power. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of Nevada Power.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Nevada Power during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Nevada Power's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Nevada Power's actual results in the future could differ significantly from the historical results.

Results of Operations

Net income for the year ended December 31, 2017 was $255 million, a decrease of $24 million, or 9%, compared to 2016, which includes $5 million of expense from the Tax Cuts and Jobs Act enacted on December 22, 2017 (the "2017 Tax Reform"). Excluding the impact of the 2017 Tax Reform, adjusted net income was $260 million, a decrease of $19 million compared to 2016, due to expenses related to the Nevada Power regulatory rate review of $28 million, higher depreciation and amortization, primarily due to higher plant placed in-service of $5 million. The decrease was partially offset by higher margins of $11 million, excluding the impact of a decrease in energy efficiency program rate revenue of $22 million (offset in operations and maintenance), and lower interest expense of $9 million on lower deferred charges and lower rates on outstanding debt balances. Margins increased due to customer usage patterns and customer growth, partially offset by lower margins from customers purchasing energy from alternative providers and becoming distribution only service customers.

Net income for the year ended December 31, 2016 was $279 million, a decrease of $9 million, or 3%, compared to 2015. Net income decreased due to lower margins from changes in usage patterns with commercial and industrial customers, lower customer usage due to customer demand and the impacts of weather, benefits from changes in contingent liabilities in 2015 and higher depreciation and amortization primarily due to higher plant placed in-service. The decrease in net income was offset by higher customer growth and lower interest expense from the redemption of $210 million Series M, 5.950% General and Refunding Mortgage Notes in 2016.

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

A comparison of Nevada Power's key operating results related to gross margin for the years ended December 31 is as follows:

	2017	2016	Change		2016	2015	Change	
Gross margin (in millions):								
Operating revenue	$ 2,206	$ 2,083	$ 123	6 %	$ 2,083	$ 2,402	$ (319)	(13)%
Cost of fuel, energy and capacity	902	768	134	17	768	1,084	(316)	(29)
Gross margin	$ 1,304	$ 1,315	$ (11)	(1)	$ 1,315	$ 1,318	$ (3)	—
GWh sold:								
Residential	9,501	9,394	107	1 %	9,394	9,246	148	2 %
Commercial	4,656	4,663	(7)	—	4,663	4,635	28	1
Industrial	6,201	7,313	(1,112)	(15)	7,313	7,571	(258)	(3)
Other	212	212	—	—	212	214	(2)	(1)
Total fully bundled(1)	20,570	21,582	(1,012)	(5)	21,582	21,666	(84)	—
Distribution only service	1,830	662	1,168	*	662	407	255	63
Total retail	22,400	22,244	156	1	22,244	22,073	171	1
Wholesale	314	258	56	22	258	353	(95)	(27)
Total GWh sold	22,714	22,502	212	1	22,502	22,426	76	—
Average number of retail customers (in thousands):								
Residential	810	796	14	2 %	796	782	14	2 %
Commercial	106	105	1	1	105	104	1	1
Industrial	2	2	—	—	2	2	—	—
Total	918	903	15	2	903	888	15	2
Average per MWh:								
Revenue - fully bundled(1)	$ 104.57	$ 94.27	$ 10.30	11 %	$ 94.27	$ 108.49	$ (14.22)	(13)%
Total cost of energy(2)	$ 41.84	$ 34.00	$ 7.84	23 %	$ 34.00	$ 48.04	$ (14.04)	(29)%
Heating degree days	1,265	1,508	(243)	(16)%	1,508	1,491	17	1 %
Cooling degree days	4,044	4,002	42	1 %	4,002	4,069	(67)	(2)%
Sources of energy (GWh)(3):								
Coal	1,449	1,480	(31)	(2)%	1,480	1,556	(76)	(5)%
Natural gas	13,172	14,577	(1,405)	(10)	14,577	14,567	10	—
Other	73	61	12	20	61	4	57	*
Total energy generated	14,694	16,118	(1,424)	(9)	16,118	16,127	(9)	—
Energy purchased	6,858	6,462	396	6	6,462	6,431	31	—
Total	21,552	22,580	(1,028)	(5)	22,580	22,558	22	—

* Not meaningful

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average total cost of energy per MWh includes the cost of fuel, purchased power and deferrals and does not include other costs.

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

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Gross margin decreased $11 million for 2017 compared to 2016 due to:

- $32 million in lower commercial and industrial retail revenue from customers purchasing energy from alternative providers and becoming distribution only service customers and
- $22 million in lower energy efficiency program rate revenue, which is offset in operations and maintenance.

The decrease in gross margin was partially offset by:

- $21 million in higher other retail revenue primarily from impact fees and revenue relating to customers becoming distribution only service customers;
- $9 million from customer usage patterns;
- $7 million due to customer growth and
- $6 million in higher transmission revenue primarily due to customers becoming distribution only service customers.

Operations and maintenance decreased $1 million for 2017 compared to 2016 due to lower energy efficiency program expense (offset in operating revenue) of $22 million and lower planned maintenance, partially offset by higher expenses related to the regulatory rate review of $25 million.

Depreciation and amortization increased $5 million, or 2%, for 2017 compared to 2016 primarily due to higher plant placed in-service.

Property and other taxes increased $2 million, or 5%, for 2017 compared to 2016 due to a reduction in property tax abatements.

Other income (expense) is favorable $3 million, or 2%, for 2017 compared to 2016 due to lower interest expense on deferred charges and the redemption of $210 million Series M, 5.950% General and Refunding Mortgage Notes in 2016, partially offset by lower allowance for funds used during construction and expenses related to the regulatory rate review.

Income tax expense increased $10 million, or 7%, for 2017 compared to 2016. The effective tax rate was 38% in 2017 and 34% in 2016. The increase in the effective tax rate is primarily due to the effects of 2017 Tax Reform and the qualified production activities deduction in 2016.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Gross margin decreased $3 million for 2016 compared to 2015 due to:

- $9 million in usage patterns for commercial and industrial customers;
- $8 million due to lower customer usage, due to the impacts of weather and
- $2 million in transmission revenue.

The decrease in gross margin was offset by:

- $16 million due to higher customer growth.

Operations and maintenance increased $22 million, or 6%, for 2016 compared to 2015 due to benefits from changes in contingent liabilities in 2015, higher generating costs and disallowances resulting from regulatory rate reviews.

Depreciation and amortization increased $6 million, or 2%, for 2016 compared to 2015 primarily due to higher plant placed in-service.

Property and other taxes increased $2 million, or 6%, for 2016 compared to 2015 due to a reduction in property tax abatements, offset by lower assessed property values.

Other income (expense) is favorable $8 million, or 5%, for 2016 compared to 2015 primarily due to lower interest expense from the redemption of $210 million Series M, 5.950% General and Refunding Mortgage Notes in 2016.

Income tax expense decreased $16 million, or 10%, for 2016 compared to 2015. The effective tax rate was 34% in 2016 and 36% in 2015. The decrease in the effective tax rate is primarily due to the qualified production activities deduction.

Liquidity and Capital Resources

As of December 31, 2017, Nevada Power's total net liquidity was $457 million as follows (in millions):

Cash and cash equivalents	$	57
Credit facilities[(1)]		400
Total net liquidity	$	457
Credit facilities:		
Maturity dates		2020

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

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2017 and 2016 were $667 million and $771 million, respectively. The change was due to higher intercompany tax payments and higher impact fees received in 2016, partially offset by a 2016 contribution to the pension plan.

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $771 million and $892 million, respectively. The change was due to decreased collections from customers due to lower retail rates as a result of deferred energy adjustment mechanisms, a 2016 contribution to the pension plan and increased operating costs. The decrease was offset by the receipt of impact fees from MGM Resorts International and Wynn Las Vegas, lower payments for fuel costs, settlement payments of contingent liabilities in 2015 and higher collections from customers for renewable energy programs.

Nevada Power's income tax cash flows benefited in 2017, 2016 and 2015 from 50% bonus depreciation on qualifying assets placed in service and from investment tax credits earned on qualifying solar projects. In December 2017, the 2017 Tax Reform was enacted which, among other items, reduces the federal corporate tax rate from 35% to 21% effective January 1, 2018, eliminates bonus depreciation on qualifying regulated utility assets acquired after September 27, 2017 and eliminates the deduction for production activities, but did not impact investment tax credits. Nevada Power believes for qualifying assets acquired on or before September 27, 2017, bonus depreciation will remain available for 2018 and 2019. In February 2018, the Nevada Utilities made filings with the PUCN proposing a tax rate reduction rider for the lower annual income tax expense anticipated to result from the 2017 Tax Reform for 2018 and beyond. The filing supports an annual rate reduction of $59 million. Nevada Power expects lower revenue and income taxes as well as lower bonus depreciation benefits as a result of the 2017 Tax Reform and related regulatory treatment. Nevada Power does not expect the 2017 Tax Reform and related regulatory treatment to have a material adverse impact on its cash flows, subject to actual regulatory outcomes. Refer to Regulatory Matters in Item 1 of this Form 10-K for further discussion of regulatory matters associated with the 2017 Tax Reform. The timing of Nevada Power's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2017 and 2016 were $(343) million and $(335) million, respectively. The change was due to the acquisition of the remaining 25% ownership in the Silverhawk generating station, partially offset by decreased capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(335) million and $(301) million, respectively. The change was due to increased capital maintenance expenditures and proceeds received from the sale of assets and an equity investment in 2015.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2017 and 2016 were $(546) million and $(693) million, respectively. The change was due to lower repayments of long-term debt and proceeds from issuance of long-term debt, partially offset by higher dividends paid to NV Energy, Inc. in 2017.

Net cash flows from financing activities for the years ended December 31, 2016 and 2015 were $(693) million and $(275) million, respectively. The change was due to higher dividends paid to NV Energy, Inc., partially offset by lower repayments of long-term debt.

Ability to Issue Debt

Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2017, Nevada Power has financing authority from the PUCN consisting of the ability to: (1) issue long-term debt securities of up to $1.3 billion; (2) refinancing authority up to $1.2 billion of long-term debt securities; and (3) maintain a revolving credit facility of up to $1.3 billion. Nevada Power's revolving credit facility contains a financial maintenance covenant which Nevada Power was in compliance with as of December 31, 2017. In addition, certain financing agreements contain covenants which are currently suspended as Nevada Power's senior secured debt is rated investment grade. However, if Nevada Power's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Nevada Power would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent Nevada Power has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Nevada Power's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Nevada Power's indenture.

Nevada Power's indenture creates a lien on substantially all of Nevada Power's properties in Nevada. As of December 31, 2017, $8.4 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $2.9 billion of additional general and refunding mortgage securities as of December 31, 2017 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Nevada Power also has the ability to release property from the lien of Nevada Power's indenture on the basis of net property additions, cash or retired bonds. To the extent Nevada Power releases property from the lien of Nevada Power's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution control technologies, replacement generation and associated operating costs are generally incorporated into Nevada Power's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

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

	Historical			Forecasted		
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Generation development	$ 45	$ 1	$ —	$ 10	$ 42	$ 18
Distribution	102	144	110	164	171	161
Transmission system investment	63	30	9	34	25	17
Other	110	160	151	120	95	93
Total	$ 320	$ 335	$ 270	$ 328	$ 333	$ 289

Nevada Power's forecast capital expenditures include investments that relate to operating projects that consist of routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand.

In April 2017, Nevada Power purchased the remaining 25% interest in the Silverhawk natural gas-fueled generating facility for $77 million. The Public Utilities Commission of Nevada ("PUCN") approved the purchase of the facility in Nevada Power's triennial Integrated Resource Plan filing in December 2015. The purchase price was allocated to the assets acquired, consisting primarily of generation utility plant, and no significant liabilities were assumed.

Contractual Obligations

Nevada Power has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes Nevada Power's material contractual cash obligations as of December 31, 2017 (in millions):

	Payments Due by Periods				
	2018	2019 - 2020	2021 - 2022	2023 and Thereafter	Total
Long-term debt	$ 823	$ 500	$ —	$ 1,309	$ 2,632
Interest payments on long-term debt(1)	155	171	154	1,195	1,675
Capital leases, including interest(2),(3)	14	27	33	28	102
ON Line financial lease, including interest(2)	44	88	88	728	948
Fuel and capacity contract commitments(1)	591	827	758	5,208	7,384
Fuel and capacity contract commitments (not commercially operable)(1)	—	37	49	421	507
Operating leases and easements(1)	7	15	15	54	91
Asset retirement obligations	4	10	14	63	91
Maintenance, service and other contracts(1)	46	87	76	40	249
Total contractual cash obligations	$ 1,684	$ 1,762	$ 1,187	$ 9,046	$ 13,679

(1) Not reflected on the Consolidated Balance Sheets.

(2) Interest is not reflected on the Consolidated Balance Sheets.

(3) Includes fuel and capacity contracts designated as a capital lease.

Nevada Power has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 6), uncertain tax positions (Note 10) and asset retirement obligations (Note 13), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

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

Environmental Laws and Regulations

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

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for Nevada Power's forecasted environmental-related capital expenditures.

Collateral and Contingent Features

Debt of Nevada Power is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Nevada Power's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Nevada Power has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Nevada Power's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, 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, 2017, Nevada Power would have been required to post $20 million of additional collateral. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of Nevada Power's collateral requirements specific to Nevada Power's derivative contracts.

Inflation

Historically, overall inflation and changing prices in the economies where Nevada Power operates has not had a significant impact on Nevada Power's consolidated financial results. Nevada Power operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, Nevada Power is allowed to include prudent costs in its rates, including the impact of inflation after Nevada Power experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Nevada Power attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Nevada Power, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Nevada Power's ability to recover its costs. Nevada Power believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $1.0 billion and total regulatory liabilities were $1.1 billion as of December 31, 2017. Refer to Nevada Power's Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's regulatory assets and liabilities.

Derivatives

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances.

Nevada Power has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. Nevada Power employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risk. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Nevada Power's Note 8 and 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by accounting principles generally accepted in the United States of America. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves.

Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2017, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs. The assumptions used in these models are critical because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2017, Nevada Power had a net derivative liability of $3 million related to contracts where Nevada Power uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

Nevada Power's commodity derivative contracts are probable of inclusion in regulated rates, and changes in the estimated fair value of derivative contracts are recorded as regulatory assets. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the amounts are reflected in regulated rates. As of December 31, 2017, Nevada Power had $3 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated 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, 2017, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

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

Income Taxes

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory jurisdictions. Nevada Power's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on Nevada Power's consolidated financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations. Refer to Nevada Power's Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's income taxes.

Nevada Power is probable to pass income tax benefits and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to its customers. As of December 31, 2017, these amounts were recognized as a net regulatory liability of $670 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $111 million as of December 31, 2017. 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 when actual revenue is recorded.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power does not hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Nevada Power's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Nevada Power's price risk on commodity contracts accounted for as derivatives, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Net Liability	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2017:			
Commodity derivative contracts	$ (3)	$ (3)	$ (3)
As of December 31, 2016:			
Commodity derivative contracts	$ (14)	$ (15)	$ (13)

Nevada Power's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Nevada Power to earnings volatility. As of December 31, 2017 and 2016, a net regulatory asset of $3 million and $14 million, respectively, was recorded related to the net derivative liability of $3 million and $14 million, respectively. The settled cost of these commodity derivative contracts is generally included in regulated rates.

Interest Rate Risk

Nevada Power is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Nevada Power's fixed-rate long-term debt does not expose Nevada Power to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Nevada Power were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Nevada Power's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Nevada Power's short- and long-term debt.

As of December 31, 2017 and 2016, Nevada Power had no short- and long-term variable-rate obligations that expose Nevada Power to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Nevada Power's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2017 and 2016.

Credit Risk

Nevada Power is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2017, Nevada Power's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Board of Directors of
Nevada Power Company
Las Vegas, Nevada

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Nevada Power Company and subsidiaries ("Nevada Power") as of December 31, 2017 and 2016, the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Nevada Power as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Nevada Power's management. Our responsibility is to express an opinion on Nevada Power's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Nevada Power in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Nevada Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Nevada Power's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 23, 2018
We have served as Nevada Power's auditor since 1987.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57	$ 279
Accounts receivable, net	238	243
Inventories	59	73
Regulatory assets	28	20
Other current assets	44	38
Total current assets	426	653
Property, plant and equipment, net	6,877	6,997
Regulatory assets	941	1,000
Other assets	35	39
Total assets	$ 8,279	$ 8,689
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 156	$ 187
Accrued interest	50	50
Accrued property, income and other taxes	63	93
Regulatory liabilities	91	37
Current portion of long-term debt and financial and capital lease obligations	842	17
Customer deposits	73	78
Other current liabilities	16	39
Total current liabilities	1,291	501
Long-term debt and financial and capital lease obligations	2,233	3,049
Regulatory liabilities	1,030	416
Deferred income taxes	767	1,474
Other long-term liabilities	280	277
Total liabilities	5,601	5,717
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $1.00 stated value, 1,000 shares authorized, issued and outstanding	—	—
Other paid-in capital	2,308	2,308
Retained earnings	374	667
Accumulated other comprehensive loss, net	(4)	(3)
Total shareholder's equity	2,678	2,972
Total liabilities and shareholder's equity	$ 8,279	$ 8,689

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	2016	2015
Operating revenue	$ 2,206	$ 2,083	$ 2,402
Operating costs and expenses:			
Cost of fuel, energy and capacity	902	768	1,084
Operations and maintenance	393	394	372
Depreciation and amortization	308	303	297
Property and other taxes	40	38	36
Total operating costs and expenses	1,643	1,503	1,789
Operating income	563	580	613
Other income (expense):			
Interest expense	(179)	(185)	(190)
Allowance for borrowed funds	1	4	3
Allowance for equity funds	1	2	4
Other, net	25	24	20
Total other income (expense)	(152)	(155)	(163)
Income before income tax expense	411	425	450
Income tax expense	156	146	162
Net income	$ 255	$ 279	$ 288

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2014	1,000	$ —	$ 2,308	$ 583	$ (3)	$ 2,888
Net income	—	—	—	288	—	288
Dividends declared	—	—	—	(13)	—	(13)
Balance, December 31, 2015	1,000	—	2,308	858	(3)	3,163
Net income	—	—	—	279	—	279
Dividends declared	—	—	—	(469)	—	(469)
Other equity transactions	—	—	—	(1)	—	(1)
Balance, December 31, 2016	1,000	—	2,308	667	(3)	2,972
Net income	—	—	—	255	—	255
Dividends declared	—	—	—	(548)	—	(548)
Other equity transactions	—	—	—	—	(1)	(1)
Balance, December 31, 2017	1,000	$ —	$ 2,308	$ 374	$ (4)	$ 2,678

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 255	$ 279	$ 288
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gain) loss on nonrecurring items	(1)	1	(3)
Depreciation and amortization	308	303	297
Deferred income taxes and amortization of investment tax credits	94	78	162
Allowance for equity funds	(1)	(2)	(4)
Changes in regulatory assets and liabilities	50	131	4
Deferred energy	(16)	(21)	176
Amortization of deferred energy	16	(107)	36
Other, net	(3)	—	13
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	8	26	(40)
Inventories	6	7	9
Accrued property, income and other taxes	(26)	63	—
Accounts payable and other liabilities	(23)	13	(46)
Net cash flows from operating activities	667	771	892
Cash flows from investing activities:			
Capital expenditures	(270)	(335)	(320)
Acquisitions	(77)	—	—
Proceeds from sale of assets	4	—	9
Other, net	—	—	10
Net cash flows from investing activities	(343)	(335)	(301)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	91	—	—
Repayments of long-term debt and financial and capital lease obligations	(89)	(224)	(262)
Dividends paid	(548)	(469)	(13)
Net cash flows from financing activities	(546)	(693)	(275)
Net change in cash and cash equivalents	(222)	(257)	316
Cash and cash equivalents at beginning of period	279	536	220
Cash and cash equivalents at end of period	$ 57	$ 279	$ 536

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

(1) Organization and Operations

Nevada Power Company, together with its subsidiaries ("Nevada Power"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Sierra Pacific Power Company ("Sierra Pacific") and certain other subsidiaries. Nevada Power is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Nevada Power and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2017, 2016 and 2015. Certain amounts in the prior period Consolidated Financial Statements have been reclassified to conform to the current period presentation. Such reclassifications did not impact previously reported operating income, net income or retained earnings.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Nevada Power's ability to recover its costs. Nevada Power believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss).

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on Nevada Power's assessment of the collectibility of amounts owed to Nevada Power by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. Nevada Power also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2017	2016	2015
Beginning balance	$ 12	$ 13	$ 14
Charged to operating costs and expenses, net	15	16	16
Write-offs, net	(11)	(17)	(17)
Ending balance	$ 16	$ 12	$ 13

Derivatives

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

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

For Nevada Power's derivative 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 a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling \$56 million and \$60 million as of December 31, 2017 and 2016, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling \$3 million and \$13 million as of December 31, 2017 and 2016, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Nevada Power capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Nevada Power's various regulatory authorities. Depreciation studies are completed by Nevada Power to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as a non-current regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Nevada Power retires or sells a component of regulated property, plant and equipment depreciated using the composite method, 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 with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory asset or liability.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Nevada Power is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Nevada Power's AFUDC rate used during 2017 and 2016 was 8.09%.

Asset Retirement Obligations

Nevada Power recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Nevada Power's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated 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, 2017, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

Berkshire Hathaway includes Nevada Power in its consolidated United States federal income tax return. Consistent with established regulatory practice, Nevada Power's provision for income taxes has been computed on a separate return basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law which, among other items, reduces the federal corporate tax rate from 35% to 21%. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences that Nevada Power deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties.

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory jurisdictions. Nevada Power's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on Nevada Power's consolidated financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2017 and 2016, unbilled revenue was $111 million and $91 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. Nevada Power records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Nevada Power primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, Nevada Power may not take physical delivery of the energy or natural gas. Nevada Power may sell the excess energy or natural gas to the wholesale market. In such instances, it is Nevada Power's policy to record such sales net in cost of fuel, energy and capacity.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing on a straight-line basis.

Segment Information

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

New Accounting Pronouncements

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, which amends FASB Accounting Standards Codification ("ASC") Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. This guidance must be adopted retrospectively for the presentation of the service cost component and the other components of net benefit cost in the statement of operations and prospectively for the capitalization of the service cost component in the balance sheet. Nevada Power adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Nevada Power adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Nevada Power adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. In January 2018, the FASB issued ASU No. 2018-01 that provides for an optional transition practical expedient allowing companies to not have to evaluate existing land easements if they were not previously accounted for under ASC Topic 840, "Leases." This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. Nevada Power plans to adopt this guidance effective January 1, 2019 and is currently evaluating the impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. During 2016 and 2017, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. Nevada Power adopted this guidance effective January 1, 2018 under the modified retrospective method and the adoption will not have an impact on its Consolidated Financial Statements but will increase the disclosures included within Notes to Consolidated Financial Statements. The timing and amount of revenue recognized after adoption of the new guidance will not be different than before as a majority of revenue is recognized when Nevada Power has the right to invoice as it corresponds directly with the value to the customer of Nevada Power's performance to date. Nevada Power's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by customer class.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2017	2016
Utility plant:			
Generation	30 - 55 years	$ 3,707	$ 4,271
Distribution	20 - 65 years	3,314	3,231
Transmission	45 - 65 years	1,860	1,846
General and intangible plant	5 - 65 years	793	738
Utility plant		9,674	10,086
Accumulated depreciation and amortization		(2,871)	(3,205)
Utility plant, net		6,803	6,881
Other non-regulated, net of accumulated depreciation and amortization	45 years	1	2
Plant, net		6,804	6,883
Construction work-in-progress		73	114
Property, plant and equipment, net		$ 6,877	$ 6,997

Almost all of Nevada Power's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Nevada Power's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2017, 2016 and 2015 was 3.2%, 3.2% and 3.0%, respectively. Nevada Power is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

During 2017, Nevada Power performed a depreciation study, in which the depreciation rates will be implemented in January 2018. The study results in shorter estimated useful lives at the Navajo Generating Station and longer average service lives for various other utility plant groups. The net effect of these changes, based on the study, will increase depreciation and amortization expense by $7 million annually based on depreciable plant balances at the time of the change.

Acquisitions

In April 2017, Nevada Power purchased the remaining 25% interest in the Silverhawk natural gas-fueled generating facility for $77 million. The Public Utilities Commission of Nevada ("PUCN") approved the purchase of the facility in Nevada Power's triennial Integrated Resource Plan filing in December 2015. The purchase price was allocated to the assets acquired, consisting primarily of generation utility plant, and no significant liabilities were assumed.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Nevada Power, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Nevada Power accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Nevada Power's share of the expenses of these facilities.

The amounts shown in the table below represent Nevada Power's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2017 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Navajo Generating Station	11%	$ 220	$ 152	$ —
ON Line Transmission Line	24	146	16	—
Other transmission facilities	Various	48	26	—
Total		$ 414	$ 194	$ —

(5) Regulatory Matters

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

	Weighted Average Remaining Life	2017	2016
Decommissioning costs	6 years	$ 231	$ 114
Deferred operating costs	12 years	169	127
Merger costs from 1999 merger	27 years	130	136
Employee benefit plans(1)	8 years	89	105
Asset retirement obligations	7 years	72	74
Abandoned projects	3 years	58	75
Legacy meters	15 years	56	60
ON Line deferrals	36 years	47	44
Deferred energy costs	2 years	46	46
Deferred income taxes(2)	N/A	—	141
Other	Various	71	98
Total regulatory assets		$ 969	$ 1,020
Reflected as:			
Current assets		$ 28	$ 20
Other assets		941	1,000
Total regulatory assets		$ 969	$ 1,020

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

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

Nevada Power had regulatory assets not earning a return on investment of $363 million and $560 million as of December 31, 2017 and 2016, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, asset retirement obligations, deferred operating costs, a portion of the employee benefit plans, losses on reacquired debt and deferred energy costs. Regulatory assets not earning a return as of December 31, 2016 also included deferred income taxes.

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

	Weighted Average Remaining Life	2017	2016
Deferred income taxes[1]	33 years	$ 670	$ 9
Cost of removal[2]	31 years	307	294
Impact fees	6 years	89	90
Energy efficiency program	1 year	27	37
Other	Various	28	23
Total regulatory liabilities		$ 1,121	$ 453
Reflected as:			
Current liabilities		$ 91	$ 37
Other long-term liabilities		1,030	416
Total regulatory liabilities		$ 1,121	$ 453

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse. See Note 10 for further discussion of 2017 Tax Reform impacts.

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

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Regulatory Rate Review

In June 2017, Nevada Power filed an electric regulatory rate review with the PUCN. The filing supported an annual revenue increase of $29 million, or 2%, but requested no incremental annual revenue relief. In December 2017, the PUCN issued an order which reduced Nevada Power's revenue requirement by $26 million and requires Nevada Power to share 50% of revenues related to equity returns above 9.7%. As a result of the order, Nevada Power recorded expense of $28 million primarily due to the reduction of a regulatory asset to return to customers revenue collected for costs not incurred. In January 2018, Nevada Power filed a petition for clarification of certain findings and directives in the order. The new rates were effective in February 2018.

Energy Efficiency Program Rates ("EEPR") and Energy Efficiency Implementation Rates ("EEIR")

EEPR was established to allow Nevada Power to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by Nevada Power and approved by the PUCN in integrated resource plan proceedings. To the extent Nevada Power's earned rate of return exceeds the rate of return used to set base general rates, Nevada Power is required to refund to customers EEIR revenue previously collected for that year. In March 2017, Nevada Power filed an application to reset the EEIR and EEPR and refund the EEIR revenue received in 2016, including carrying charges. In September 2017, the PUCN issued an order accepting a stipulation requiring Nevada Power to refund the 2016 revenue and reset the rates as filed effective October 1, 2017. The EEIR liability for Nevada Power is $10 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2017 and 2016.

Chapter 704B Applications

Chapter 704B of the Nevada Revised Statutes allows retail electric customers with an average annual load of one megawatt ("MW") or more to file with the PUCN an application to purchase energy from alternative providers of a new electric resource and become distribution only service customers. On a case-by-case basis, the PUCN will assess the application and may deny or grant the application subject to conditions, including paying an impact fee, paying on-going charges and receiving approval for specific alternative energy providers and terms. The impact fee and on-going charges are assessed to alleviate the burden on other Nevada customers for the applicant's share of previously committed investments and long-term renewable contracts and are set at a level designed such that the remaining customers are not subjected to increased costs.

In May 2015, MGM Resorts International ("MGM") and Wynn Las Vegas, LLC ("Wynn"), filed applications with the PUCN to purchase energy from alternative providers of a new electric resource and become distribution only service customers of Nevada Power. In December 2015, the PUCN granted the applications subject to conditions, including paying an impact fee, on-going charges and receiving approval for specific alternative energy providers and terms. In December 2015, the applicants filed petitions for reconsideration. In January 2016, the PUCN granted reconsideration and updated some of the terms, including removing a limitation related to energy purchased indirectly from NV Energy. In September 2016, MGM and Wynn paid impact fees of $82 million and $15 million, respectively. In October 2016, MGM and Wynn became distribution only service customers and started procuring energy from another energy supplier. In April 2017, Wynn filed a motion with the PUCN seeking relief from the January 2016 order and requested the PUCN adopt an alternative impact fee and revise on-going charges associated with retirement of assets and high cost renewable contracts. This request is still pending. In May 2017, a stipulation reached between MGM, Regulatory Operations Staff and the Bureau of Consumer Protection was filed requiring Nevada Power to reduce the original $82 million impact fee by $16 million and apply the credit against MGM's remaining on-going charge obligation. In June 2017, the PUCN approved the stipulation as filed.

In September 2016, Switch, Ltd. ("Switch"), a customer of Nevada Power, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Nevada Power. In December 2016, the PUCN approved a stipulation agreement that allows Switch to purchase energy from alternative providers subject to conditions, including paying an impact fee to Nevada Power. In May 2017, Switch paid impact fees of $27 million and, in June 2017, Switch became a distribution only service customer and started procuring energy from another energy supplier.

In November 2016, Caesars Enterprise Service ("Caesars"), a customer of Nevada Power, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Nevada Power. In March 2017, the PUCN approved the application allowing Caesars to purchase energy from alternative providers subject to conditions, including paying an impact fee. In March 2017, Caesars provided notice that it intends to pay the impact fee monthly for six years and proceed with purchasing energy from alternative providers. In July 2017, Caesars made the required compliance filings and, in September 2017, the PUCN issued an order allowing Caesars to acquire electric energy and ancillary services from another energy supplier and become a distribution only service customer of Nevada Power. In December 2017, Caesars provided notice that it intends to transition eligible meters in the Nevada Power service territory to unbundled electric service in February 2018 at the earliest.

Emissions Reduction and Capacity Retirement Plan ("ERCR Plan")

In March 2017, Nevada Power retired Reid Gardner Unit 4, a 257-MW coal-fueled generating facility. The early retirement was approved by the PUCN in December 2016 as a part of Nevada Power's second amendment to the ERCR Plan. The remaining net book value of $151 million was moved from property, plant and equipment, net to noncurrent regulatory assets on the Consolidated Balance Sheet in March 2017, in compliance with the ERCR Plan. Refer to Note 14 for additional information on the ERCR Plan.

(6) Credit Facility

Nevada Power has a $400 million secured credit facility expiring in June 2020 with two one-year extension options subject to lender consent. The credit facility, which is for general corporate purposes and provide for the issuance of letters of credit, has a variable interest rate based on the Eurodollar rate or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's credit ratings for its senior secured long-term debt securities. As of December 31, 2017 and 2016, Nevada Power had no borrowings outstanding under the credit facility. Amounts due under Nevada Power's credit facility are collateralized by Nevada Power's general and refunding mortgage bonds. The credit facility requires Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

(7) Long-Term Debt and Financial and Capital Lease Obligations

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

	Par Value	2017	2016
General and refunding mortgage securities:			
6.500% Series O, due 2018	$ 324	$ 324	$ 324
6.500% Series S, due 2018	499	499	498
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	357	357
6.750% Series R, due 2037	349	346	345
5.375% Series X, due 2040	250	247	247
5.450% Series Y, due 2041	250	236	236
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.800% Pollution Control Bonds Series 2017A, due 2032[(1)]	40	40	—
1.600% Pollution Control Bonds Series 2017, due 2036[(1)]	40	39	—
1.600% Pollution Control Bonds Series 2017B, due 2039[(1)]	13	13	—
Variable-rate series - 1.890% to 1.928%			
Pollution Control Bonds Series 2006A, due 2032	—	—	38
Pollution Control Bonds Series 2006, due 2036	—	—	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	475	475	485
Total long-term debt and financial and capital leases	$ 3,107	$ 3,075	$ 3,066

	2017	2016
Reflected as:		
Current portion of long-term debt and financial and capital lease obligations	$ 842	$ 17
Long-term debt and financial and capital lease obligations	2,233	3,049
Total long-term debt and financial and capital leases	$ 3,075	$ 3,066

(1) Subject to mandatory purchase by Nevada Power in May 2020 at which date the interest rate may be adjusted from time to time.

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2018 and thereafter, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2018	$ 823	$ 75	$ 898
2019	500	76	576
2020	—	76	76
2021	—	80	80
2022	—	75	75
Thereafter	1,309	760	2,069
Total	2,632	1,142	3,774
Unamortized premium, discount and debt issuance cost	(32)	—	(32)
Executory costs	—	(92)	(92)
Amounts representing interest	—	(575)	(575)
Total	$ 2,600	$ 475	$ 3,075

The issuance of General and Refunding Mortgage Securities by Nevada Power is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2017, approximately $8.4 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- In 1984, Nevada Power entered into a 30-year capital lease for the Pearson Building with five, five-year renewal options beginning in year 2015. In February 2010, Nevada Power amended this capital lease agreement to include the lease of the adjoining parking lot and to exercise three of the five-year renewal options beginning in year 2015. There remain two additional renewal options which could extend the lease an additional ten years. Capital assets of $24 million and $25 million were included in property, plant and equipment, net as of December 31, 2017 and 2016, respectively.
- In 2007, Nevada Power entered into a 20-year lease, with three 10-year renewal options, to occupy land and building for its Beltway Complex operations center in southern Nevada. Nevada Power accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. Nevada Power transferred operations to the facilities in June 2009. Capital assets of $6 million and $7 million were included in property, plant and equipment, net as of December 31, 2017 and 2016, respectively.
- Nevada Power has long-term energy purchase contracts which qualify as capital leases. The leases were entered into between the years 1989 and 1990 and became commercially operable through 1993. The terms of the leases are for 30 years and expire between the years 2022-2023. Capital assets of $34 million and $38 million were included in property, plant and equipment, net as of December 31, 2017 and 2016, respectively.
- Nevada Power has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement. Capital assets of $3 million and $1 million were included in property, plant and equipment, net as of December 31, 2017 and 2016, respectively.
- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 4 for additional information. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 95% for Nevada Power and 5% for Sierra Pacific. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $396 million and $402 million were included in property, plant and equipment, net as of December 31, 2017 and 2016, respectively.

(8) Risk Management and Hedging Activities

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

Nevada Power has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Nevada Power's accounting policies related to derivatives. Refer to Notes 2 and 9 for additional information on derivative contracts.

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

	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2017:			
Commodity derivative liabilities(1)	$ (2)	$ (1)	$ (3)
As of December 31, 2016:			
Commodity derivative liabilities(1)	$ (7)	$ (7)	$ (14)

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates and as of December 31, 2017 and 2016, a regulatory asset of $3 million and $14 million, respectively, was recorded related to the derivative liability of $3 million and $14 million, respectively.

Derivative Contract Volumes

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

	Unit of Measure	2017	2016
Electricity sales	Megawatt hours	—	(2)
Natural gas purchases	Decatherms	125	114

Credit Risk

Nevada Power is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide rights to demand cash or other security in the event of a credit rating downgrade ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of Nevada Power's derivative contracts in liability positions with specific credit-risk-related contingent features was $1 million and $2 million as of December 31, 2017 and 2016, respectively, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(9) Fair Value Measurements

The carrying value of Nevada Power's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Nevada Power has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Nevada Power has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Nevada Power's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Nevada Power develops these inputs based on the best information available, including its own data.

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

	Input Levels for Fair Value Measurements			
	Level 1	**Level 2**	**Level 3**	**Total**
As of December 31, 2017:				
Assets - investment funds	$ 2	$ —	$ —	$ 2
Liabilities - commodity derivatives	$ —	$ —	$ (3)	$ (3)
As of December 31, 2016:				
Assets:				
Money market mutual funds[(1)]	$ 220	$ —	$ —	$ 220
Investment funds	6	—	—	6
	$ 226	$ —	$ —	$ 226
Liabilities - commodity derivatives	$ —	$ —	$ (14)	$ (14)

(1) Amounts are included in cash and cash equivalents 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 Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2017, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs. Refer to Note 8 for further discussion regarding Nevada Power's risk management and hedging activities.

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

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

	2017	**2016**	**2015**
Beginning balance	$ (14)	$ (22)	$ (30)
Changes in fair value recognized in regulatory assets	(3)	(4)	—
Settlements	14	12	8
Ending balance	$ (3)	$ (14)	$ (22)

Nevada Power's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Nevada Power's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of Nevada Power's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of Nevada Power's long-term debt as of December 31 (in millions):

	2017		2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 2,600	$ 3,088	$ 2,581	$ 3,040

(10) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018, limitations on bonus depreciation for utility property and the elimination of the deduction for production activities. GAAP requires the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, Nevada Power reduced deferred income tax liabilities $787 million. As it is probable the change in deferred taxes will be passed back to customers through regulatory mechanisms, Nevada Power increased net regulatory liabilities by $792 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. Nevada Power has recorded the impacts of the 2017 Tax Reform and believes all the impacts to be complete with the exception of the interpretation of the bonus depreciation rules. Nevada Power has determined the amounts recorded and the interpretation relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. Nevada Power believes its interpretations for bonus depreciation to be reasonable, however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

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

	2017	2016	2015
Current – Federal	$ 62	$ 68	$ —
Deferred – Federal	95	79	163
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 156	$ 146	$ 162

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:

	2017	2016	2015
Federal statutory income tax rate	35%	35%	35%
Effect of ratemaking	1	—	1
Effect of tax rate change	1	—	—
Other	1	(1)	—
Effective income tax rate	38%	34%	36%

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

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 201	$ 83
Capital and financial leases	100	170
Employee benefits	18	29
Customer advances	14	23
Federal net operating loss and credit carryforwards	—	5
Other	6	16
Total deferred income tax assets	339	326
Valuation allowance	—	(5)
Total deferred income tax assets, net	339	321
Deferred income tax liabilities:		
Property related items	(796)	(1,293)
Regulatory assets	(206)	(321)
Capital and financial leases	(97)	(165)
Other	(7)	(16)
Total deferred income tax liabilities	(1,106)	(1,795)
Net deferred income tax liability	$ (767)	$ (1,474)

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

(11) Related Party Transactions

Nevada Power has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to Nevada Power under this agreement totaled $2 million for the year ended December 31, 2017, 2016 and 2015.

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $66 million, $68 million and $68 million for each of the years ended December 31, 2017, 2016 and 2015. As of December 31, 2017 and 2016, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $5 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $3 million, $2 million and $3 million for the years ended December 31, 2017, 2016 and 2015, respectively. There were no receivables associated with these services as of December 31, 2017 and 2016. PacifiCorp provided electricity and the sale of renewable energy credits to Nevada Power of $- million, $- million and $2 million for the years ended December 31, 2017, 2016 and 2015, respectively. There were no payables associated with these transactions as of December 31, 2017 and 2016.

Nevada Power provided electricity to Sierra Pacific of $104 million, $78 million and $69 million for the years ended December 31, 2017, 2016 and 2015, respectively. Receivables associated with these transactions were $10 million and $45 million as of December 31, 2017 and 2016, respectively. Nevada Power purchased electricity from Sierra Pacific of $21 million, $17 million and $2 million for the years ended December 31, 2017, 2016 and 2015, respectively. Payables associated with these transactions were $- million and $12 million as of December 31, 2017 and 2016, respectively.

Nevada Power incurs intercompany administrative and shared facility costs with NV Energy and Sierra Pacific. These transactions are governed by an intercompany service agreement and are priced at cost. Nevada Power provided services to NV Energy of $- million, $1 million, $1 million for each of the years ending December 31, 2017, 2016 and 2015, respectively. NV Energy provided services to Nevada Power of $10 million, $10 million and $12 million for the years ending December 31, 2017, 2016 and 2015, respectively. Nevada Power provided services to Sierra Pacific of $27 million, $24 million and $22 million for the years ended December 31, 2017, 2016 and 2015, respectively. Sierra Pacific provided services to Nevada Power of $17 million, $14 million and $16 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $29 million and $32 million, respectively. There were no receivables due from NV Energy as of December 31, 2017 and 2016. As of December 31, 2017 and 2016, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $5 million and $4 million, respectively. There were no payables due to Sierra Pacific as of December 31, 2017 and 2016.

Nevada Power is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated United States federal income tax return. Federal income taxes payable to NV Energy were $38 million and $68 million as of December 31, 2017 and 2016, respectively. Nevada Power made cash payments of $89 million, $- million and $- million for federal income taxes for the years ended December 31, 2017, 2016 and 2015, respectively.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Nevada Power and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(12) Retirement Plan and Postretirement Benefits

Nevada Power is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Nevada Power. Nevada Power contributed $1 million, $36 million and $- million to the Qualified Pension Plan for the year ended December 31, 2017, 2016 and 2015, respectively. Nevada Power contributed $1 million, $- million and $- million to the Non-Qualified Pension Plans for the year ended December 31, 2017, 2016 and 2015, respectively. Nevada Power did not make any contributions to the Other Postretirement Plans for the year ended December 31, 2017, 2016 and 2015. Amounts attributable to Nevada Power were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2017	2016
Qualified Pension Plan -		
Other long-term liabilities	$ (23)	$ (24)
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(10)	(9)
Other Postretirement Plans -		
Other long-term liabilities	1	(4)

(13) Asset Retirement Obligations

Nevada Power estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Nevada Power does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $307 million and $294 million as of December 31, 2017 and 2016, respectively.

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

	2017	2016
Waste water remediation	$ 39	$ 38
Evaporative ponds and dry ash landfills	11	22
Asbestos	3	4
Solar	3	2
Other	24	17
Total asset retirement obligations	$ 80	$ 83

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

	2017	2016
Beginning balance	$ 83	$ 85
Change in estimated costs	6	4
Retirements	(13)	(10)
Accretion	4	4
Ending balance	$ 80	$ 83
Reflected as:		
Other current liabilities	$ 4	$ 20
Other long-term liabilities	76	63
	$ 80	$ 83

In 2008, Nevada Power signed an administrative order of consent as owner and operator of Reid Gardner Generating Station Unit Nos. 1, 2 and 3 and as co-owner and operating agent of Unit No. 4. Based on the administrative order of consent, Nevada Power recorded estimated AROs and capital remediation costs. However, actual costs of work under the administrative order of consent may vary significantly once the scope of work is defined and additional site characterization has been completed. In connection with the termination of the co-ownership arrangement, effective October 22, 2013, between Nevada Power and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, Nevada Power and CDWR entered into a cost-sharing agreement that sets forth how the parties will jointly share in costs associated with all investigation, characterization and, if necessary, remedial activities as required under the administrative order of consent.

Certain of Nevada Power's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Nevada Power is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Management has identified legal obligations to retire generation plant assets specified in land leases for Nevada Power's jointly-owned Navajo Generating Station and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. Nevada Power's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

(14) Commitments and Contingencies

Environmental Laws and Regulations

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

Senate Bill 123

In June 2013, the Nevada State Legislature passed Senate Bill No. 123 ("SB 123"), which included the retirement of coal plants and replacing the capacity with renewable facilities and other generating facilities. In May 2014, Nevada Power filed its ERCR Plan in compliance with SB 123. In July 2015, Nevada Power filed an amendment to its ERCR Plan with the PUCN which was approved in September 2015. In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123.

Consistent with the ERCR Plan, Nevada Power acquired a 272-MW natural gas co-generating facility in 2014, acquired a 210-MW natural gas peaking facility in 2014, constructed a 15-MW solar photovoltaic facility in 2015, contracted two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities in 2015, contracted a renewable power purchase agreement with 100-MW solar photovoltaic generating facility in 2016 and acquired the remaining 130 MW, 25%, of the Silverhawk natural gas-fueled generating facility in April 2017, of which 54 MW were approved as part of the ERCR Plan. Nevada Power has the option to acquire 35 MW of nameplate renewable energy capacity in the future under the ERCR Plan, subject to PUCN approval. Nevada Power retired Reid Gardner Units 1, 2, and 3, 300 MW of coal-fueled generation, in 2014 and Reid Gardner Unit 4, 257 MW of coal-fueled generation, in March 2017. These transactions are related to Nevada Power's compliance with SB 123, resulting in the retirement of 812 MW of coal-fueled generation by 2019.

Legal Matters

Nevada Power is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Nevada Power does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. Nevada Power 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.

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2017 are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 591	$ 450	$ 377	$ 378	$ 380	$ 5,208	$ 7,384
Fuel and capacity contract commitments (not commercially operable)	—	15	22	24	25	421	507
Operating leases and easements	7	7	8	8	7	54	91
Maintenance, service and other contracts	46	44	43	39	37	40	249
Total commitments	$ 644	$ 516	$ 450	$ 449	$ 449	$ 5,723	$ 8,231

Fuel and Capacity Contract Commitments

Purchased Power

Nevada Power has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2018 to 2067. Purchased power includes contracts which meet the definition of a lease. Nevada Power's operations and maintenance expense for purchase power contracts which met the lease criteria for 2017, 2016 and 2015 were $310 million, $302 million and $264 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

Nevada Power has a contract for the transportation of coal that extends through 2018. Additionally, gas transportation contracts expire from 2022 to 2032 and the gas supply contract expires from 2018 to 2019.

Fuel and Capacity Contract Commitments - Not Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Operating Leases and Easements

Nevada Power has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. These leases generally require Nevada Power to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Nevada Power also has non-cancelable easements for land. Operations and maintenance expense on non-cancelable operating leases and easements totaled $9 million, $13 million and $11 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Maintenance, Service and Other Contracts

Nevada Power has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2019 to 2026.

(15) Supplemental Cash Flow Disclosures

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

	2017	2016	2015
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 167	$ 173	$ 186
Income taxes paid	$ 89	$ —	$ —
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 18	$ 19	$ 51
Capital and financial lease obligations incurred	$ —	$ (1)	$ (5)

(16) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017
Operating revenues	$ 392	$ 574	$ 819	$ 421
Operating income	52	157	317	37
Net income	10	77	176	(8)

	Three-Month Periods Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Operating revenues	$ 399	$ 525	$ 766	$ 393
Operating income	46	141	324	69
Net income	3	66	188	22

Sierra Pacific Power Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

Sierra Pacific's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy, natural gas and resources. Sierra Pacific's electric segment is summer peaking experiencing its highest retail energy sales in response to the demand for air conditioning and its natural gas segment is winter peaking due to sales in response to the demand for heating. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of Sierra Pacific. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of Sierra Pacific.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Sierra Pacific during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Sierra Pacific's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Sierra Pacific's actual results in the future could differ significantly from the historical results.

Results of Operations

Net income for the year ended December 31, 2017 was $109 million, an increase of $25 million, or 30%, compared to 2016, which includes $1 million of tax benefit from the Tax Cuts and Jobs Act enacted on December 22, 2017 (the "2017 Tax Reform"). Excluding the impact of 2017 Tax Reform, adjusted net income was $108 million, an increase of $24 million compared to 2016, due to lower interest on deferred charges and long-term debt of $11 million, higher electric margins of $8 million, lower depreciation and amortization primarily due to regulatory amortizations of $4 million and lower operating costs of $4 million. The increase in electric margin was due to the impacts of weather, higher transmission revenue and customer usage patterns, partially offset by lower wholesale revenue due to lower volumes.

Net income for the year ended December 31, 2016 was $84 million, an increase of $1 million, or 1%, compared to 2015. Net income increased due to a decrease in interest expense from financing transactions in 2016 of $8 million, increased customer growth and usage primarily due to the impacts of weather of $7 million and lower planned maintenance costs. The increase in net income was partially offset by disallowances resulting from the settlement of the regulatory rate review in 2016 of $5 million, higher depreciation and amortization primarily due to higher plant placed in-service of $5 million, a settlement payment associated with terminated transmission service in 2015 of $4 million and lower margins from a decrease in wholesale demand charges and changes in usage patterns with commercial and industrial customers.

Operating revenue; cost of fuel, energy and capacity; and natural gas purchased for resale are key drivers of Sierra Pacific's results of operations as they encompass retail and wholesale electricity and natural gas revenue and the direct costs associated with providing electricity and natural gas to customers. Sierra Pacific believes that a discussion of gross margin, representing operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale, is therefore meaningful.

Electric Gross Margin

A comparison of Sierra Pacific's key operating results related to regulated electric gross margin for the years ended December 31 is as follows:

	2017	2016	Change		2016	2015	Change	
Gross margin (in millions):								
Operating electric revenue	$ 713	$ 702	$ 11	2 %	$ 702	$ 810	$ (108)	(13)%
Cost of fuel, energy and capacity	268	265	3	1	265	374	(109)	(29)
Gross margin	$ 445	$ 437	$ 8	2	$ 437	$ 436	$ 1	—
GWh sold:								
Residential	2,492	2,375	117	5 %	2,375	2,315	60	3 %
Commercial	2,954	2,933	21	1	2,933	2,942	(9)	—
Industrial	3,176	3,014	162	5	3,014	2,973	41	1
Other	16	16	—	—	16	16	—	—
Total fully bundled[(1)]	8,638	8,338	300	4	8,338	8,246	92	1
Distribution only service	1,394	1,360	34	3	1,360	1,304	56	4
Total retail	10,032	9,698	334	3	9,698	9,550	148	2
Wholesale	561	662	(101)	(15)	662	664	(2)	—
Total GWh sold	10,593	10,360	233	2	10,360	10,214	146	1
Average number of retail customers (in thousands):								
Residential	295	291	4	1 %	291	288	3	1 %
Commercial	47	47	—	—	47	46	1	2
Total	342	338	4	1	338	334	4	1
Average per MWh:								
Revenue - retail fully bundled[(1)]	$ 76.90	$ 78.08	$ (1.18)	(2)%	$ 78.08	$ 90.85	$ (12.77)	(14)%
Revenue - wholesale	$ 50.29	$ 52.05	$ (1.76)	(3)%	$ 52.05	$ 61.37	$ (9.32)	(15)%
Total cost of energy[(2)]	$ 27.35	$ 28.16	$ (0.81)	(3)%	$ 28.16	$ 38.80	$ (10.64)	(27)%
Heating degree days	4,523	4,185	338	8 %	4,185	4,122	63	2 %
Cooling degree days	1,401	1,088	313	29 %	1,088	1,194	(106)	(9)%
Sources of energy (GWh)[(3)]:								
Coal	457	751	(294)	(39)%	751	1,210	(459)	(38)%
Natural gas	4,280	4,290	(10)	—	4,290	3,981	309	8
Other	36	—	36	—	—	—	—	—
Total energy generated	4,773	5,041	(268)	(5)	5,041	5,191	(150)	(3)
Energy purchased	5,017	4,383	634	14	4,383	4,441	(58)	(1)
Total	9,790	9,424	366	4	9,424	9,632	(208)	(2)

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average total cost of energy per MWh includes the cost of fuel, purchased power and deferrals and does not include other costs.

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

Natural Gas Gross Margin

A comparison of key results related to regulated natural gas gross margin for the years ended December 31 is as follows:

	2017	2016	Change		2016	2015	Change	
Gross margin (in millions):								
Operating natural gas revenue	$ 99	$ 110	$ (11)	(10)%	$ 110	$ 137	$ (27)	(20)%
Natural gas purchased for resale	42	55	(13)	(24)	55	84	(29)	(35)
Gross margin	$ 57	$ 55	$ 2	4	$ 55	$ 53	$ 2	4
Dth sold:								
Residential	10,291	9,207	1,084	12 %	9,207	8,649	558	6 %
Commercial	5,153	4,679	474	10	4,679	4,198	481	11
Industrial	1,822	1,548	274	18	1,548	1,470	78	5
Total retail	17,266	15,434	1,832	12	15,434	14,317	1,117	8
Average number of retail customers (in thousands)	164	162	2	1 %	162	159	3	2 %
Average revenue per retail Dth sold:	$ 5.73	$ 7.13	$ (1.40)	(20)%	$ 7.13	$ 9.57	$ (2.44)	(25)%
Average cost of natural gas per retail Dth sold	$ 2.43	$ 3.56	$ (1.13)	(32)%	$ 3.56	$ 5.87	$ (2.31)	(39)%
Heating degree days	4,523	4,185	338	8 %	4,185	4,122	63	2 %

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Electric gross margin increased $8 million, or 2%, for 2017 compared to 2016 due to:

- $8 million higher customer usage primarily from the impacts of weather;
- $3 million in higher transmission revenue and
- $2 million from customer usage patterns.

The increase in gross margin was offset by:

- $6 million in decreased wholesale revenue due to lower volumes.

Natural gas gross margin increased $2 million, or 4%, for 2017 compared to 2016 primarily due to higher customer usage from the impacts of weather.

Operations and maintenance decreased $4 million, or 2%, for 2017 compared to 2016 primarily due to disallowances resulting from the settlement of the regulatory rate review in 2016 of $5 million.

Depreciation and amortization decreased $4 million, or 3%, for 2017 compared to 2016 primarily due to the expiration of various regulatory amortizations.

Other income (expense) is favorable $13 million, or 28%, for 2017 compared to 2016 primarily due to a decrease in interest expense from lower rates on outstanding debt balances, lower interest expense on deferred charges and an increase in allowance for funds used during construction.

Income tax expense increased $6 million, or 12%, for 2017 compared to 2016. The effective tax rate was 34% for 2017 and 37% for 2016. The decrease in the effective tax rate is primarily due to the effects of 2017 Tax Reform.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Electric gross margin increased $1 million for 2016 compared to 2015 due to:

- $4 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense;
- $3 million in higher customer growth and
- $2 million in higher customer usage primarily due to the impacts of weather.

The increase in gross margin was offset by:

- $4 million related to a settlement payment associated with terminated transmission service in 2015;
- $2 million decrease in wholesale demand charges and
- $2 million in usage patterns for commercial and industrial customers.

Natural gas gross margin increased $2 million, or 4%, for 2016 compared to 2015 primarily due to higher customer usage from the impacts of weather.

Operations and maintenance increased $3 million, or 2%, for 2016 compared to 2015 due to disallowances resulting from the settlement of the regulatory rate review in 2016 of $5 million and higher energy efficiency program costs, which are fully recovered in operating revenue, partially offset by decreased planned maintenance costs.

Depreciation and amortization increased $5 million, or 4%, for 2016 compared to 2015 primarily due to higher plant placed in-service.

Other income (expense) is favorable $7 million, or 13%, for 2016 compared to 2015 primarily due to a decrease in interest expense from financing transactions in 2016.

Income tax expense increased $2 million, or 4%, for 2016 compared to 2015. The effective tax rate was 37% for 2016 and 36% for 2015.

Liquidity and Capital Resources

As of December 31, 2017, Sierra Pacific's total net liquidity was $174 million as follows (in millions):

Cash and cash equivalents	$	4
Credit facilities[1]		250
Less -		
Letters of credit and tax-exempt bond support		(80)
Net credit facilities		170
Total net liquidity	$	174
Credit facilities:		
Maturity dates		2020

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

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2017 and 2016 were $182 million and $243 million, respectively. The change was due to higher payments for fuel costs, partially offset by lower contributions to the pension plan.

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $243 million and $342 million, respectively. The change was due to decreased collections from customers due to lower retail rates as a result of deferred energy adjustment mechanisms, contributions to the pension plan and lower customer advances, partially offset by lower payments for fuel costs.

Sierra Pacific's income tax cash flows benefited in 2017, 2016 and 2015 from 50% bonus depreciation on qualifying assets placed in service. In December 2017, the 2017 Tax Reform was enacted which, among other items, reduces the federal corporate tax rate from 35% to 21% effective January 1, 2018, eliminates bonus depreciation on qualifying regulated utility assets acquired after September 27, 2017 and eliminates the deduction for production activities. Sierra Pacific believes for qualifying assets acquired on or before September 27, 2017, bonus depreciation will remain available for 2018 and 2019. In February 2018, the Nevada Utilities made filings with the PUCN proposing a tax rate reduction rider for the lower annual income tax expense anticipated to result from the 2017 Tax Reform for 2018 and beyond. The filing supports an annual rate reduction of $25 million. Sierra Pacific expects lower revenue and income taxes as well as lower bonus depreciation benefits as a result of the 2017 Tax Reform and related regulatory treatment. Sierra Pacific does not expect the 2017 Tax Reform and related regulatory treatment to have a material adverse impact on its cash flows, subject to actual regulatory outcomes. Refer to Regulatory Matters in Item 1 of this Form 10-K for further discussion of regulatory matters associated with the 2017 Tax Reform. The timing of Sierra Pacific's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2017 and 2016 were $(186) million and $(194) million, respectively. The change was primarily due to decreased capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(194) million and $(250) million, respectively. The change was primarily due to decreased capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2017 and 2016 were $(47) million and $(100) million, respectively. The change was due to lower repayments of long-term debt and lower dividends paid to NV Energy, Inc. in 2017, offset by lower proceeds from issuance of long-term debt.

Net cash flows from financing activities for the years ended December 31, 2016 and 2015 were $(100) million and $(8) million, respectively. The change was due to financing transactions in 2016 and higher dividends paid to NV Energy, Inc.

Ability to Issue Debt

Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2017, Sierra Pacific has financing authority from the PUCN consisting of the ability to: (1) issue additional long-term debt securities of up to $350 million; (2) refinance up to $55 million of long-term debt securities; and (3) maintain a revolving credit facility of up to $600 million. Sierra Pacific's revolving credit facility contains a financial maintenance covenant which Sierra Pacific was in compliance with as of December 31, 2017. In addition, certain financing agreements contain covenants which are currently suspended as Sierra Pacific's senior secured debt is rated investment grade. However, if Sierra Pacific's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Sierra Pacific would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent Sierra Pacific has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Sierra Pacific's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Sierra Pacific's indenture.

Sierra Pacific's indenture creates a lien on substantially all of Sierra Pacific's properties in Nevada. As of December 31, 2017, $3.9 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $1.2 billion of additional general and refunding mortgage securities as of December 31, 2017 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Sierra Pacific also has the ability to release property from the lien of Sierra Pacific's indenture on the basis of net property additions, cash or retired bonds. To the extent Sierra Pacific releases property from the lien of Sierra Pacific's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution-control technologies, replacement generation and associated operating costs are generally incorporated into Sierra Pacific's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

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

	Historical			Forecasted		
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Distribution	$ 86	$ 115	$ 88	$ 81	$ 76	64
Transmission system investment	38	12	12	11	47	15
Other	128	67	86	104	101	80
Total	$ 252	$ 194	$ 186	$ 196	$ 224	$ 159

Sierra Pacific's forecast capital expenditures include investments that relate to operating projects that consist of routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

Sierra Pacific has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes Sierra Pacific's material contractual cash obligations as of December 31, 2017 (in millions):

	Payments Due by Periods				
	2018	**2019 - 2020**	**2021 - 2022**	**2023 and Thereafter**	**Total**
Long-term debt	$ —	$ —	$ —	$ 1,121	$ 1,121
Interest payments on long-term debt(1)	40	81	81	351	553
Capital leases, including interest(2)	3	4	2	8	17
ON Line financial lease, including interest(2)	2	4	5	38	49
Fuel and capacity contract commitments(1)	200	269	145	515	1,129
Fuel and capacity contract commitments (not commercially operable)(1)	—	24	44	590	658
Operating leases and easements(1)	4	8	5	54	71
Asset retirement obligations	—	—	—	14	14
Maintenance, service and other contracts(1)	6	12	12	12	42
Total contractual cash obligations	$ 255	$ 402	$ 294	$ 2,703	$ 3,654

(1) Not reflected on the Consolidated Balance Sheets.

(2) Interest is not reflected on the Consolidated Balance Sheets.

Sierra Pacific has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 6), uncertain tax positions (Note 9) and asset retirement obligations (Note 12), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

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

Environmental Laws and Regulations

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

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for Sierra Pacific's forecasted environmental-related capital expenditures.

Collateral and Contingent Features

Debt of Sierra Pacific is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Sierra Pacific's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Sierra Pacific has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Sierra Pacific's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2017, 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, 2017, Sierra Pacific would have been required to post $15 million of additional collateral. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where Sierra Pacific operates has not had a significant impact on Sierra Pacific's consolidated financial results. Sierra Pacific operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, Sierra Pacific is allowed to include prudent costs in its rates, including the impact of inflation after Sierra Pacific experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Sierra Pacific attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Sierra Pacific, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Sierra Pacific's ability to recover its costs. Sierra Pacific believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $332 million and total regulatory liabilities were $500 million as of December 31, 2017. Refer to Sierra Pacific's Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated 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, 2017, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

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

Income Taxes

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory jurisdictions. Sierra Pacific's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on Sierra Pacific's consolidated financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations. Refer to Sierra Pacific's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's income taxes.

Sierra Pacific is probable to pass income tax benefits and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to its customers. As of December 31, 2017, these amounts were recognized as a net regulatory liability of $264 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $62 million as of December 31, 2017. 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 when actual revenue is recorded.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Sierra Pacific uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Sierra Pacific does not hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Sierra Pacific's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

Interest Rate Risk

Sierra Pacific is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Sierra Pacific manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Sierra Pacific's fixed-rate long-term debt does not expose Sierra Pacific to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Sierra Pacific were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Sierra Pacific's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Sierra Pacific's short- and long-term debt.

As of December 31, 2017 and 2016, Sierra Pacific had short- and long-term variable-rate obligations totaling $80 million, that expose Sierra Pacific to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Sierra Pacific's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2017 and 2016.

Credit Risk

Sierra Pacific is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Sierra Pacific enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2017, Sierra Pacific's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Board of Directors of
Sierra Pacific Power Company
Las Vegas, Nevada

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries ("Sierra Pacific") as of December 31, 2017 and 2016, the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Sierra Pacific as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Sierra Pacific's management. Our responsibility is to express an opinion on Sierra Pacific's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Sierra Pacific in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Sierra Pacific is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Sierra Pacific's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 23, 2018
We have served as Sierra Pacific's auditor since 1996.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31, 2017	As of December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4	$ 55
Accounts receivable, net	112	117
Inventories	49	45
Regulatory assets	32	25
Other current assets	17	13
Total current assets	214	255
Property, plant and equipment, net	2,892	2,822
Regulatory assets	300	410
Other assets	7	6
Total assets	$ 3,413	$ 3,493
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 92	$ 146
Accrued interest	14	14
Accrued property, income and other taxes	10	10
Regulatory liabilities	19	69
Current portion of long-term debt and financial and capital lease obligations	2	1
Customer deposits	15	16
Other current liabilities	12	12
Total current liabilities	164	268
Long-term debt and financial and capital lease obligations	1,152	1,152
Regulatory liabilities	481	221
Deferred income taxes	330	617
Other long-term liabilities	114	127
Total liabilities	2,241	2,385
Commitments and contingencies (Note 13)		
Shareholder's equity:		
Common stock - $3.75 stated value, 20,000,000 shares authorized and 1,000 issued and outstanding	—	—
Other paid-in capital	1,111	1,111
Retained earnings (accumulated deficit)	62	(2)
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	1,172	1,108
Total liabilities and shareholder's equity	$ 3,413	$ 3,493

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	2016	2015
Operating revenue:			
Electric	$ 713	$ 702	$ 810
Natural gas	99	110	137
Total operating revenue	812	812	947
Operating costs and expenses:			
Cost of fuel, energy and capacity	268	265	374
Natural gas purchased for resale	42	55	84
Operations and maintenance	166	170	167
Depreciation and amortization	114	118	113
Property and other taxes	24	24	25
Total operating costs and expenses	614	632	763
Operating income	198	180	184
Other income (expense):			
Interest expense	(43)	(54)	(61)
Allowance for borrowed funds	2	4	2
Allowance for equity funds	3	(1)	2
Other, net	4	4	3
Total other income (expense)	(34)	(47)	(54)
Income before income tax expense	164	133	130
Income tax expense	55	49	47
Net income	$ 109	$ 84	$ 83

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2014	1,000	$ —	$ 1,111	$ (111)	$ (2)	$ 998
Net income	—	—	—	83	—	83
Dividends declared	—	—	—	(7)	—	(7)
Other equity transactions	—	—	—	—	2	2
Balance, December 31, 2015	1,000	—	1,111	(35)	—	1,076
Net income	—	—	—	84	—	84
Dividends declared	—	—	—	(51)	—	(51)
Other equity transactions	—	—	—	—	(1)	(1)
Balance, December 31, 2016	1,000	—	1,111	(2)	(1)	1,108
Net income	—	—	—	109	—	109
Dividends declared	—	—	—	(45)	—	(45)
Balance, December 31, 2017	1,000	$ —	$ 1,111	$ 62	$ (1)	$ 1,172

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 109	$ 84	$ 83
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss on nonrecurring items	—	5	—
Depreciation and amortization	114	118	113
Allowance for equity funds	(4)	1	(2)
Deferred income taxes and amortization of investment tax credits	55	49	47
Changes in regulatory assets and liabilities	17	(17)	(21)
Deferred energy	(20)	53	81
Amortization of deferred energy	(47)	(54)	17
Other, net	(3)	—	(9)
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	4	7	15
Inventories	(3)	(6)	1
Accrued property, income and other taxes	1	(3)	—
Accounts payable and other liabilities	(41)	6	17
Net cash flows from operating activities	182	243	342
Cash flows from investing activities:			
Capital expenditures	(186)	(194)	(252)
Other, net	—	—	2
Net cash flows from investing activities	(186)	(194)	(250)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	—	1,089	—
Repayments of long-term debt and financial and capital lease obligations	(2)	(1,138)	(1)
Dividends paid	(45)	(51)	(7)
Net cash flows from financing activities	(47)	(100)	(8)
Net change in cash and cash equivalents	(51)	(51)	84
Cash and cash equivalents at beginning of period	55	106	22
Cash and cash equivalents at end of period	$ 4	$ 55	$ 106

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

(1) Organization and Operations

Sierra Pacific Power Company, together with its subsidiaries ("Sierra Pacific"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Nevada Power Company ("Nevada Power") and certain other subsidiaries. Sierra Pacific is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers and regulated retail natural gas customers primarily in northern Nevada. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Sierra Pacific and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2017, 2016 and 2015. Certain amounts in the prior period Consolidated Financial Statements have been reclassified to conform to the current period presentation. Such reclassifications did not impact previously reported operating income, net income or retained earnings.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Sierra Pacific's ability to recover its costs. Sierra Pacific believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss).

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on Sierra Pacific's assessment of the collectibility of amounts owed to Sierra Pacific by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. Sierra Pacific also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2017	2016	2015
Beginning balance	$ 2	$ 1	$ 2
Charged to operating costs and expenses, net	2	2	1
Write-offs, net	(2)	(1)	(2)
Ending balance	$ 2	$ 2	$ 1

Derivatives

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

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity or natural gas purchased for resale on the Consolidated Statements of Operations.

For Sierra Pacific's derivative 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 a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $42 million and $36 million as of December 31, 2017 and 2016, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $7 million and $9 million as of December 31, 2017 and 2016, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Sierra Pacific capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Sierra Pacific's various regulatory authorities. Depreciation studies are completed by Sierra Pacific to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as a non-current regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Sierra Pacific retires or sells a component of regulated property, plant and equipment depreciated using the composite method, 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 with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory asset or liability.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Sierra Pacific is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Sierra Pacific's AFUDC rate used during 2017 and 2016 was 6.65% and 7.62% for electric, 5.63% and 6.02% for natural gas, and 6.55% and 7.44% for common facilities, respectively.

Asset Retirement Obligations

Sierra Pacific recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Sierra Pacific's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated 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, 2017, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

Berkshire Hathaway includes Sierra Pacific in its consolidated United States federal income tax return. Consistent with established regulatory practice, Sierra Pacific's provision for income taxes has been computed on a separate return basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law which, among other items, reduces the federal corporate tax rate from 35% to 21%. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences that Sierra Pacific deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties.

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory jurisdictions. Sierra Pacific's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on Sierra Pacific's consolidated financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

Revenue Recognition

Revenue is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2017 and 2016, unbilled revenue was $62 million and $52 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. Sierra Pacific records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Sierra Pacific primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, Sierra Pacific may not take physical delivery of the energy or natural gas. Sierra Pacific may sell the excess energy or natural gas to the wholesale market. In such instances, it is Sierra Pacific's policy to allocate the natural gas sales between generation and natural gas retail based on usage. The energy sales and natural gas sales allocated to generation are recorded net in cost of fuel, energy and capacity. The natural gas sales allocated to natural gas retail is recorded as wholesale revenue.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing on a straight-line basis.

New Accounting Pronouncements

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, which amends FASB Accounting Standards Codification ("ASC") Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. This guidance must be adopted retrospectively for the presentation of the service cost component and the other components of net benefit cost in the statement of operations and prospectively for the capitalization of the service cost component in the balance sheet. Sierra Pacific adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Sierra Pacific adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Sierra Pacific adopted this guidance effective January 1, 2018 and the adoption will not have a material impact on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. In January 2018, the FASB issued ASU No. 2018-01 that provides for an optional transition practical expedient allowing companies to not have to evaluate existing land easements if they were not previously accounted for under ASC Topic 840, "Leases." This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. Sierra Pacific plans to adopt this guidance effective January 1, 2019 and is currently evaluating the impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. During 2016 and 2017, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. Sierra Pacific adopted this guidance effective January 1, 2018 under the modified retrospective method and the adoption will not have an impact on its Consolidated Financial Statements but will increase the disclosures included within Notes to Consolidated Financial Statements. The timing and amount of revenue recognized after adoption of the new guidance will not be different than before as a majority of revenue is recognized when Sierra Pacific has the right to invoice as it corresponds directly with the value to the customer of Sierra Pacific's performance to date. Sierra Pacific's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by segment and customer class.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2017	2016
Utility plant:			
Electric generation	25 - 60 years	$ 1,144	$ 1,137
Electric distribution	20 - 100 years	1,459	1,417
Electric transmission	50 - 100 years	786	771
Electric general and intangible plant	5 - 70 years	181	164
Natural gas distribution	35 - 70 years	390	381
Natural gas general and intangible plant	5 - 70 years	14	15
Common general	5 - 70 years	294	267
Utility plant		4,268	4,152
Accumulated depreciation and amortization		(1,513)	(1,442)
Utility plant, net		2,755	2,710
Other non-regulated, net of accumulated depreciation and amortization	70 years	5	5
Plant, net		2,760	2,715
Construction work-in-progress		132	107
Property, plant and equipment, net		$ 2,892	$ 2,822

All of Sierra Pacific's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Sierra Pacific's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2017, 2016 and 2015 was 3.0%, 3.0% and 2.9%, respectively. Sierra Pacific is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

In January 2017, Sierra Pacific revised its electric and gas depreciation rates based on the results of a new depreciation study performed in 2016, the most significant impact of which was shorter estimated useful lives at the Valmy Generating Station. The effect of this change increased depreciation and amortization expense by $9 million annually based on depreciable plant balances at the time of the study. However, the PUCN ordered the change relating to the Valmy Generating Station of $7 million annually be deferred for future recovery through a regulatory asset.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Sierra Pacific, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Sierra Pacific accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Sierra Pacific's share of the expenses of these facilities.

The amounts shown in the table below represent Sierra Pacific's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2017 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50%	$ 388	$ 233	$ 1
ON Line Transmission Line	1	8	1	—
Valmy Transmission	50	4	2	—
Total		$ 400	$ 236	$ 1

(5) Regulatory Matters

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

	Weighted Average Remaining Life	2017	2016
Employee benefit plans[1]	8 years	$ 110	$ 128
Merger costs from 1999 merger	29 years	77	80
Abandoned projects	7 years	34	39
Renewable energy programs	2 years	23	25
Losses on reacquired debt	16 years	21	22
Deferred income taxes[2]	N/A	—	85
Other	Various	67	56
Total regulatory assets		$ 332	$ 435
Reflected as:			
Current assets		$ 32	$ 25
Other assets		300	410
Total regulatory assets		$ 332	$ 435

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

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

Sierra Pacific had regulatory assets not earning a return on investment of $188 million and $305 million as of December 31, 2017 and 2016, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, a portion of the employee benefit plans, losses on reacquired debt, asset retirement obligations and legacy meters. Regulatory assets not earning a return as of December 31, 2016 also included deferred income taxes.

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

	Weighted Average Remaining Life	2017	2016
Deferred income taxes(1)	29 years	$ 264	$ 6
Cost of removal(2)	41 years	211	205
Deferred energy costs	2 years	8	64
Other	Various	17	15
Total regulatory liabilities		$ 500	$ 290
Reflected as:			
Current liabilities		$ 19	$ 69
Other long-term liabilities		481	221
Total regulatory liabilities		$ 500	$ 290

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to accelerated tax depreciation and certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse. See Note 9 for further discussion of 2017 Tax Reform impacts.

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

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Regulatory Rate Review

In June 2016, Sierra Pacific filed an electric regulatory rate review with the PUCN. The filing requested no incremental annual revenue relief. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving most, but not all, issues in the proceeding and reduced Sierra Pacific's electric revenue requirement by $3 million spread evenly to all rate classes. In December 2016, the PUCN approved the settlement agreement and established an additional six MW of net metering capacity under the grandfathered rates, which are those net metering rates that were in effect prior to January 2016; the order establishes cost-based rates and a value-based excess energy credit for customers who choose to install private generation after the six MW limitation is reached. The new rates were effective January 1, 2017. In January 2017, Sierra Pacific filed a petition for reconsideration relating to the creation of the additional six MW of net metering at the grandfathered rates. Sierra Pacific believes the effects of the PUCN decision results in additional cost shifting to non-net metering customers and reduces the stipulated rate reduction for other customer classes. In June 2017, the PUCN denied the petition for reconsideration.

In June 2016, Sierra Pacific filed a gas regulatory rate review with the PUCN. The filing requested a slight decrease in its incremental annual revenue requirement. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving all issues in the proceeding and reduced Sierra Pacific's gas revenue requirement by $2 million. In December 2016, the PUCN approved the settlement agreement. The new rates were effective January 1, 2017.

Energy Efficiency Program Rates ("EEPR") and Energy Efficiency Implementation Rates ("EEIR")

EEPR was established to allow Sierra Pacific to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by Sierra Pacific and approved by the PUCN in integrated resource plan proceedings. To the extent Sierra Pacific's earned rate of return exceeds the rate of return used to set base general rates, Sierra Pacific is required to refund to customers EEIR revenue previously collected for that year. In March 2017, Sierra Pacific filed an application to reset the EEIR and EEPR. In September 2017, the PUCN issued an order accepting a stipulation to reset the rates as filed effective October 1, 2017. The EEIR liability for Sierra Pacific is $1 million and $2 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2017 and 2016, respectively.

Chapter 704B Applications

Chapter 704B of the Nevada Revised Statutes allows retail electric customers with an average annual load of one megawatt ("MW") or more to file with the PUCN an application to purchase energy from alternative providers of a new electric resource and become distribution only service customers. On a case-by-case basis, the PUCN will assess the application and may deny or grant the application subject to conditions, including paying an impact fee, paying on-going charges and receiving approval for specific alternative energy providers and terms. The impact fee and on-going charges are assessed to alleviate the burden on other Nevada customers for the applicant's share of previously committed investments and long-term renewable contracts and are set at a level designed such that the remaining customers are not subjected to increased costs.

In September 2016, Switch, Ltd. ("Switch"), a customer of Sierra Pacific, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Sierra Pacific. In December 2016, the PUCN approved a stipulation agreement that allows Switch to purchase energy from alternative providers without paying an impact fee, subject to conditions. In June 2017, Switch became a distribution only service customer and started procuring energy from another energy supplier.

In November 2016, Caesars Enterprise Service ("Caesars"), a customer of Sierra Pacific, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Sierra Pacific. In March 2017, the PUCN approved the application allowing Caesars to purchase energy from alternative providers subject to conditions, including paying an impact fee. In March 2017, Caesars provided notice that it intends to pay the impact fee monthly for three years and proceed with purchasing energy from alternative providers. In July 2017, Caesars made the required compliance filings and, in September 2017, the PUCN issued an order allowing Caesars to acquire electric energy and ancillary services from another energy supplier and become a distribution only service customer of Sierra Pacific. In January 2018, Caesars became a distribution only service customer and started procuring energy from another energy supplier for its eligible meters in the Sierra Pacific service territory.

In May 2017, Peppermill Resort Spa Casino ("Peppermill"), a customer of Sierra Pacific, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Sierra Pacific. In August 2017, the PUCN approved a stipulation allowing Peppermill to purchase energy from alternative providers subject to conditions, including paying an impact fee. In September 2017, Peppermill provided notice that it intends to pay the impact fee and proceed with purchasing energy from alternative providers.

(6) Credit Facility

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

	2017	2016
Credit facilities	$ 250	$ 250
Less - Water Facilities Refunding Revenue Bond support	(80)	(80)
Net credit facilities	$ 170	$ 170

Sierra Pacific has a $250 million secured credit facility expiring in June 2020 with two one-year extension options subject to lender consent. The credit facility, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on the Eurodollar rate or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's credit ratings for its senior secured long-term debt securities. As of December 31, 2017 and 2016, Sierra Pacific had no borrowings outstanding under the credit facility. Amounts due under Sierra Pacific's credit facility are collateralized by Sierra Pacific's general and refunding mortgage bonds. The credit facility requires Sierra Pacific's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

(7) Long-Term Debt and Financial and Capital Lease Obligations

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

	Par Value	2017	2016
General and refunding mortgage securities:			
3.375% Series T, due 2023	$ 250	$ 248	$ 248
2.600% Series U, due 2026	400	396	395
6.750% Series P, due 2037	252	255	255
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.250% Pollution Control Series 2016A, due 2029(1)	20	20	20
1.500% Gas Facilities Series 2016A, due 2031(1)	59	58	58
3.000% Gas and Water Series 2016B, due 2036(2)	60	63	64
Variable-rate series (2017 - 1.690% to 1.840%, 2016 - 0.788% to 0.800%):			
Water Facilities Series 2016C, due 2036	30	30	29
Water Facilities Series 2016D, due 2036	25	25	25
Water Facilities Series 2016E, due 2036	25	25	25
Capital and financial lease obligations (2017 - 2.700% to 10.396%, 2016 - 2.700% to 10.130%), due through 2054	34	34	34
Total long-term debt and financial and capital leases	$ 1,155	$ 1,154	$ 1,153
Reflected as:			
Current portion of long-term debt and financial and capital lease obligations		$ 2	$ 1
Long-term debt and financial and capital lease obligations		1,152	1,152
Total long-term debt and financial and capital leases		$ 1,154	$ 1,153

(1) Subject to mandatory purchase by Sierra Pacific in June 2019 at which date the interest rate may be adjusted from time to time.

(2) Subject to mandatory purchase by Sierra Pacific in June 2022 at which date the interest rate may be adjusted from time to time.

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2018 and thereafter, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2018	$ —	$ 4	$ 4
2019	—	4	4
2020	—	4	4
2021	—	4	4
2022	—	3	3
Thereafter	1,121	47	1,168
Total	1,121	66	1,187
Unamortized premium, discount and debt issuance cost	(1)	—	(1)
Amounts representing interest	—	(32)	(32)
Total	$ 1,120	$ 34	$ 1,154

The issuance of General and Refunding Mortgage Securities by Sierra Pacific is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2017, approximately $3.9 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- Sierra Pacific has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement. Capital assets of $3 million were included in property, plant and equipment, net as of December 31, 2017 and 2016.
- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 4 for additional information. The Nevada Utilities share of the long-term transmission use agreement and ownership interest is split at 5% for Sierra Pacific and 95% for Nevada Power. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $21 million were included in property, plant and equipment, net as of December 31, 2017 and 2016.
- In 2015, Sierra Pacific entered into a 20-year capital lease for the Fort Churchill Solar Array. Capital assets of $9 million and $10 million were included in property, plant and equipment, net as of December 31, 2017 and 2016, respectively.

(8) Fair Value Measurements

The carrying value of Sierra Pacific'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. Sierra Pacific has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Sierra Pacific has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Sierra Pacific's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Sierra Pacific develops these inputs based on the best information available, including its own data.

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

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2017:				
Assets - investment funds	$ —	$ —	$ —	$ —
As of December 31, 2016:				
Assets:				
Money market mutual funds[1]	$ 35	$ —	$ —	$ 35
Investment funds	1	—	—	1
	$ 36	$ —	$ —	$ 36

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

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

Sierra Pacific's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Sierra Pacific's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of Sierra Pacific's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of Sierra Pacific's long-term debt as of December 31 (in millions):

	2017		2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,120	$ 1,221	$ 1,119	$ 1,191

(9) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018, limitations on bonus depreciation for utility property and the elimination of the deduction for production activities. GAAP requires the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, Sierra Pacific reduced deferred income tax liabilities $342 million. As it is probable the change in deferred taxes will be passed back to customers through regulatory mechanisms, Sierra Pacific increased net regulatory liabilities by $341 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. Sierra Pacific has recorded the impacts of the 2017 Tax Reform and believes all the impacts to be complete with the exception of the interpretation of the bonus depreciation rules. Sierra Pacific has determined the amounts recorded and the interpretation relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. Sierra Pacific believes its interpretations for bonus depreciation to be reasonable, however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

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

	2017	2016	2015
Deferred - Federal	$ 56	$ 50	$ 48
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 55	$ 49	$ 47

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

	2017	2016	2015
Federal statutory income tax rate	35%	35%	35%
Effects of ratemaking	—	1	1
Effect of tax rate change	(1)	—	—
Other	—	1	—
Effective income tax rate	34%	37%	36%

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

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 67	$ 16
Federal net operating loss and credit carryforwards	10	25
Employee benefit plans	10	22
Capital and financial leases	7	12
Customer Advances	7	9
Commodity derivative contract	—	5
Other	6	6
Total deferred income tax assets	107	95
Deferred income tax liabilities:		
Property related items	(349)	(562)
Regulatory assets	(74)	(124)
Capital and financial leases	(7)	(12)
Other	(7)	(14)
Total deferred income tax liabilities	(437)	(712)
Net deferred income tax liability	$ (330)	$ (617)

The following table provides Sierra Pacific's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2017 (in millions):

Net operating loss carryforwards	$	18
Deferred income taxes on federal net operating loss carryforwards	$	4
Expiration dates	2033	
Other tax credits	$	6
Expiration dates	2021 - 2032	

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

(10) Related Party Transactions

Sierra Pacific has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to Sierra Pacific under this agreement totaled $1 million for the year ended December 31, 2017, 2016 and 2015.

Sierra Pacific provided electricity to Nevada Power of $21 million, $17 million and $2 million for the years ended December 31, 2017, 2016 and 2015, respectively. Receivables associated with these transactions were $- million and $12 million as of December 31, 2017 and 2016. Sierra Pacific purchased electricity from Nevada Power of $104 million, $78 million and $69 million for the years ended December 31, 2017, 2016 and 2015, respectively. Payables associated with these transactions were $10 million and $45 million as of December 31, 2017 and 2016, respectively.

Sierra Pacific incurs intercompany administrative and shared facility costs with NV Energy and Nevada Power. These transactions are governed by an intercompany service agreement and are priced at cost. NV Energy provided services to Sierra Pacific of $5 million, $5 million and $6 million for the years ending December 31, 2017, 2016 and 2015, respectively. Sierra Pacific provided services to Nevada Power of $17 million, $14 million, and $16 million for the years ended December 31, 2017, 2016 and 2015, respectively. Nevada Power provided services to Sierra Pacific of $27 million, $24 million, and $22 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $17 million and $18 million, respectively. There were no receivables due from NV Energy as of December 31, 2017 and 2016. As of December 31, 2017 and 2016, Sierra Pacific's Consolidated Balance Sheets included payables due to Nevada Power of $5 million and $4 million, respectively. There were no receivables due from Nevada Power as of December 31, 2017 and 2016.

Sierra Pacific is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated United States federal income tax return. There were no federal income taxes payable to NV Energy as of December 31, 2017 and 2016. No cash payments were made for federal income taxes for the years ended December 31, 2017, 2016 and 2015.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Sierra Pacific and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(11) Retirement Plan and Postretirement Benefits

Sierra Pacific is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Sierra Pacific. Sierra Pacific contributed $1 million, $27 million and $- million to the Qualified Pension Plan for the year ended December 31, 2017, 2016 and 2015, respectively. For the Other Postretirement Plans, Sierra Pacific contributed $4 million, $1 million and $- million for the year ended December 31, 2017, 2016 and 2015, respectively. Sierra Pacific contributed $1 million, $- million and $- million to the Non-Qualified Pension Plans for the year ended December 31, 2017, 2016 and 2015, respectively. Amounts attributable to Sierra Pacific were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts payable to NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2017	2016
Qualified Pension Plan -		
Other long-term liabilities	$ (2)	$ (12)
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(8)	(9)
Other Postretirement Plans -		
Other long-term liabilities	(20)	(28)

(12) Asset Retirement Obligations

Sierra Pacific estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Sierra Pacific does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $211 million and $205 million as of December 31, 2017 and 2016, respectively.

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

	2017	2016
Asbestos	$ 5	$ 4
Evaporative ponds and dry ash landfills	2	3
Other	3	3
Total asset retirement obligations	$ 10	$ 10

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

	2017	2016
Beginning balance	$ 10	$ 10
Retirements	—	—
Ending balance	$ 10	$ 10
Reflected as:		
Other current liabilities	$ —	$ —
Other long-term liabilities	10	10
	$ 10	$ 10

Certain of Sierra Pacific's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Sierra Pacific is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Sierra Pacific's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

(13) Commitments and Contingencies

Environmental Laws and Regulations

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

Legal Matters

Sierra Pacific is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Sierra Pacific does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2017 are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 200	$ 155	$ 114	$ 74	$ 71	$ 515	$ 1,129
Fuel and capacity contract commitments (not commercially operable)	—	7	17	22	22	590	658
Operating leases and easements	4	4	4	3	2	54	71
Maintenance, service and other contracts	6	6	6	7	5	12	42
Total commitments	$ 210	$ 172	$ 141	$ 106	$ 100	$ 1,171	$ 1,900

Fuel and Capacity Contract Commitments

Purchased Power

Sierra Pacific has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2018 to 2045. Purchased power includes contracts which meet the definition of a lease. Sierra Pacific's operating and maintenance expense for purchase power contracts which met the lease criteria for 2017, 2016 and 2015 were $74 million, $69 million and $65 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

Sierra Pacific has a long-term contract for the transport of coal that expires in 2018. Additionally, gas transportation contracts expire from 2019 to 2046 and the gas supply contracts expire from 2018 to 2019.

Operating Leases and Easements

Sierra Pacific has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. These leases generally require Sierra Pacific to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Sierra Pacific also has non-cancelable easements for land. Operating and maintenance expense on non-cancelable operating leases and easements totaled $4 million, $6 million and $7 million for the year-ended December 31, 2017, 2016 and 2015, respectively.

Maintenance, Service and Other Contracts

Sierra Pacific has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2019 to 2039.

(14) Supplemental Cash Flow Disclosures

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

	2017	2016	2015
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 40	$ 47	$ 54
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 10	$ 15	$ 24
Capital and financial lease obligations incurred	$ 1	$ —	$ 13

(15) Segment Information

Sierra Pacific has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by the PUCN; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance.

Sierra Pacific believes presenting gross margin allows the reader to assess the impact of Sierra Pacific's regulatory treatment and its overall regulatory environment on a consistent basis and is meaningful. Gross margin is calculated as operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale ("cost of sales").

The following tables provide information on a reportable segment basis for the years ended December 31 (in millions):

	Years Ended December 31, 2017	2016	2015
Operating revenue:			
Regulated electric	$ 713	$ 702	$ 810
Regulated gas	99	110	137
Total operating revenue	$ 812	$ 812	$ 947
Cost of sales:			
Regulated electric	$ 268	$ 265	$ 374
Regulated gas	42	55	84
Total cost of sales	$ 310	$ 320	$ 458
Gross margin:			
Regulated electric	$ 445	$ 437	$ 436
Regulated gas	57	55	53
Total gross margin	$ 502	$ 492	$ 489
Operating and maintenance:			
Regulated electric	$ 148	$ 153	$ 149
Regulated gas	18	17	18
Total operating and maintenance	$ 166	$ 170	$ 167
Depreciation and amortization:			
Regulated electric	$ 100	$ 101	$ 96
Regulated gas	14	17	17
Total depreciation and amortization	$ 114	$ 118	$ 113
Operating income:			
Regulated electric	$ 176	$ 161	$ 168
Regulated gas	22	19	16
Total operating income	$ 198	$ 180	$ 184
Interest expense:			
Regulated electric	$ 39	$ 49	$ 56
Regulated gas	4	5	5
Total interest expense	$ 43	$ 54	$ 61
Income tax expense:			
Regulated electric	$ 48	$ 44	$ 43
Regulated gas	7	5	4
Total income tax expense	$ 55	$ 49	$ 47

	Years Ended December 31,		
	2017	2016	2015
Capital expenditures:			
Regulated electric	$ 169	$ 176	$ 229
Regulated gas	17	18	23
Total capital expenditures	$ 186	$ 194	$ 252

	As of December 31,		
Total assets:	2017	2016	2015
Regulated electric	$ 3,103	$ 3,119	$ 3,060
Regulated gas	300	314	316
Regulated common assets[1]	10	60	111
Total assets	$ 3,413	$ 3,493	$ 3,487

(1) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments.

(16) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017
Regulated electric operating revenue	$ 159	$ 160	$ 215	$ 179
Regulated natural gas operating revenue	34	17	15	33
Operating income	46	36	75	41
Net income	24	17	44	24

	Three-Month Periods Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Regulated electric operating revenue	$ 170	$ 162	$ 207	$ 163
Regulated natural gas operating revenue	47	19	15	29
Operating income	41	28	69	42
Net income	17	10	38	19

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company carried out separate evaluations, under the supervision and with the participation of each such entity's management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon these evaluations, management of each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, concluded that the disclosure controls and procedures for such entity were effective to ensure that information required to be disclosed by such entity in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to its management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, as appropriate to allow timely decisions regarding required disclosure by it. Each such entity hereby states that there has been no change in its internal control over financial reporting during the quarter ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company, respectively, is responsible for establishing and maintaining, for such entity, adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of management for each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, such management conducted an evaluation for the relevant entity of the effectiveness of internal control over financial reporting as of December 31, 2017, as required by the Securities Exchange Act of 1934 Rule 13a-15 (c). In making this assessment, management for each such respective entity used the criteria set forth in the framework in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (2013)," management for each such respective entity concluded that internal control over financial reporting for such entity was effective as of December 31, 2017.

Berkshire Hathaway Energy Company	PacifiCorp	MidAmerican Funding, LLC
February 23, 2018	February 23, 2018	February 23, 2018
MidAmerican Energy Company	Nevada Power Company	Sierra Pacific Power Company
February 23, 2018	February 23, 2018	February 23, 2018

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

PACIFICORP

PacifiCorp is an indirect subsidiary of BHE, and its directors consist of executive management from both BHE and PacifiCorp. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of February 16, 2018, with respect to the current directors and executive officers of PacifiCorp:

WILLIAM J. FEHRMAN, 57, Chairman of the Board of Directors and Chief Executive Officer since January 2018. Mr. Fehrman has also been President, Chief Executive Officer and director of BHE since January 2018. Mr. Fehrman was Chief Executive Officer of MidAmerican Energy Company from 2008 to January2018 and President and director from 2007 to January 2018. Mr. Fehrman joined BHE in 2006 and has extensive executive management experience in the energy industry with strong regulatory and operational skills.

STEFAN A. BIRD, 51, President and Chief Executive Officer of Pacific Power and director since 2015. Mr. Bird was Senior Vice President, Commercial and Trading, of PacifiCorp Energy from 2007 to 2014. Mr. Bird joined BHE in 1998 and has significant operational, public policy and leadership experience in the energy industry, including expertise in energy supply management, resource acquisition and federal and state regulatory matters.

CINDY A. CRANE, 56, President and Chief Executive Officer of Rocky Mountain Power since 2014 and director since 2015. Ms. Crane was Vice President of Interwest Mining Company, a subsidiary of PacifiCorp, from 2009 to 2014. Ms. Crane joined PacifiCorp in 1990 and has significant strategy, operational and leadership experience in the energy industry, including complex commercial negotiations.

NIKKI L. KOBLIHA, 45, Vice President and Chief Financial Officer since 2015 and Treasurer and director since 2017. Ms. Kobliha joined PacifiCorp in 1997 and has significant financial, accounting and leadership experience in the energy industry, including expertise in financial reporting to the SEC and FERC.

PATRICK J. GOODMAN, 51, Director since 2006. Mr. Goodman has been Executive Vice President and Chief Financial Officer of BHE since 2012 and was Senior Vice President and Chief Financial Officer of BHE from 1999 to 2012. Mr. Goodman joined BHE in 1995 and has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury and tax functions. Mr. Goodman is also a manager of MidAmerican Funding, LLC.

NATALIE L. HOCKEN, 48, Director since 2007. Ms. Hocken has been Senior Vice President and General Counsel of BHE since 2015 and Corporate Secretary since 2017. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. Ms. Hocken joined PacifiCorp in 2002 and has significant experience in the utility industry, including expertise in transmission, legal matters and federal and state regulatory matters. Ms. Hocken is also a manager of MidAmerican Funding, LLC.

Board's Role in the Risk Oversight Process

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

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2017, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by BHE. However, the audit committee of BHE acts as the audit committee for PacifiCorp.

Code of Ethics

PacifiCorp has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

PACIFICORP

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

Mr. Gregory E. Abel, PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer, or Chairman and CEO, received no direct compensation from PacifiCorp. PacifiCorp reimbursed its indirect parent company, BHE, for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. On January 10, 2018, Mr. Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and Mr. William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

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

How is Compensation Determined

PacifiCorp's compensation committee consists solely of the Chairman and CEO. On January 10, 2018, Mr. Fehrman replaced Mr. Abel as the sole member of PacifiCorp's compensation committee. Mr. Fehrman also serves as BHE's President and Chief Executive Officer. The Chairman and CEO is responsible for the establishment and oversight of PacifiCorp's compensation policy and for approving compensation decisions for its NEOs such as approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

PacifiCorp's criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. PacifiCorp does not specifically use other companies as benchmarks when establishing its NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

PacifiCorp determines base salaries for all of its NEOs, other than the Chairman and CEO, by reviewing its overall performance, and each NEO's performance, the value each NEO brings to PacifiCorp and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than the Chairman and CEO, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. All merit increases are approved by the Chairman and CEO and take effect in the last payroll period of the year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibilities during the year. For 2017, base salaries for all NEOs, other than the Chairman and CEO, increased on average by 2.55% effective December 26, 2016, reflecting merit increases.

Short-Term Incentive Compensation

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

Annual Incentive Plan

Under PacifiCorp's Annual Incentive Plan, or AIP, all NEOs, other than the Chairman and CEO, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at the Chairman and CEO's sole discretion and is not based on a specific formula or cap. The Chairman and CEO considers a variety of factors in determining each NEO's annual incentive award including the NEO's performance, PacifiCorp's overall performance and each NEO's contribution to that overall performance. The Chairman and CEO evaluates performance using financial and non-financial objectives, including customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the Chairman and CEO's determination regarding the amounts paid to each NEO under the AIP for 2017. Approved awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the AIP, PacifiCorp may grant cash performance awards periodically during the year to one or more NEOs, other than the Chairman and CEO, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chairman and CEO. In 2017, a cash performance award was granted to Mr. Bird and Ms. Crane in recognition of their outstanding efforts.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. PacifiCorp's current long-term incentive compensation program is cash-based. PacifiCorp does not utilize stock options or other forms of equity-based awards.

Long-Term Incentive Partnership Plan

The PacifiCorp Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align PacifiCorp's interests and the interests of the participating employees. All of PacifiCorp's NEOs, other than the Chairman and CEO, participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated by January of each plan year. The BHE Chairman and PacifiCorp's Presidents approve eligibility to participate in the LTIP and the amount of the incentive award. Awards are capped at 1.0 times base salary and finalized in the first quarter of the following year. The BHE Chairman and PacifiCorp's Presidents may grant a supplemental award to any participant for the award year separate from the incentive award, subject to the same terms and conditions as the incentive award. PacifiCorp's Presidents may participate in the LTIP but only the BHE Chairman shall make determinations regarding their participation and the value of their incentive award. These cash-based awards are subject to mandatory deferral and equal annual vesting over a four-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the four-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

Deferred Compensation Plan

PacifiCorp's Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs, other than the Chairman and CEO, to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. PacifiCorp includes the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment alternatives offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits PacifiCorp to make discretionary contributions on behalf of participants.

Potential Payments Upon Termination

PacifiCorp's NEOs, other than the Chairman and CEO, are not entitled to severance or enhanced benefits upon termination of employment or change in control. However, upon any termination of employment, PacifiCorp's other NEOs would be entitled to the vested balances in the LTIP, DCP and PacifiCorp's non-contributory defined benefit pension plan, or the Retirement Plan.

Compensation Committee Report

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

William J. Fehrman

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of PacifiCorp's NEOs during the years indicated:

Name and Principal Position	Year	Base Salary	Bonus [1]	Change in Pension Value and Nonqualified Deferred Compensation Earnings [2]	All Other Compensation [3]	Total [4]
Gregory E. Abel [5][6]	2017	$ —	$ —	$ —	$ —	$ —
Chairman of the Board of Directors	2016	—	—	—	—	—
and Chief Executive Officer	2015	—	—	—	—	—
Stefan A. Bird	2017	346,000	1,116,105	9,480	30,965	1,502,550
President and Chief Executive	2016	338,000	738,784	629	13,958	1,091,371
Officer, Pacific Power	2015	313,275	844,634	13,201	12,614	1,183,724
Cindy A. Crane	2017	346,000	1,252,241	45,016	31,938	1,675,195
President and Chief Executive	2016	338,000	758,248	35,752	15,841	1,147,841
Officer, Rocky Mountain Power	2015	324,028	758,656	8,589	13,429	1,104,702
Nikki L. Kobliha	2017	217,079	122,400	18,304	30,415	388,198
Vice President, Chief Financial Officer and Treasurer	2016	203,900	143,004	9,728	29,585	386,217
	2015	177,384	91,758	—	27,253	296,395

(1) Consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs, performance awards for Mr. Bird and Ms. Crane in recognition of efforts to support PacifiCorp's objectives and the vesting of LTIP awards and associated vested earnings. The breakout for 2017 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings	Total
Stefan A. Bird	$ 500,000	$ 100,000	$ 503,178	$ 12,927	$ 516,105
Cindy A. Crane	500,000	100,000	479,093	173,148	652,241
Nikki L. Kobliha	75,000	—	46,750	650	47,400

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. BHE's Chairman and PacifiCorp's Presidents establish the award categories for determining LTIP awards based on net income target goals or other criteria. In 2017, the gross award was subjectively determined at the discretion of the BHE Chairman and PacifiCorp Presidents based on the overall achievement of PacifiCorp's financial and non-financial objectives including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which includes the Retirement Plan. Refer to the Pension Benefits table below for a discussion of the assumptions used in calculating these amounts. No participant in PacifiCorp's nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of PacifiCorp K Plus Employee Savings Plan, or 401(k) Plan, contributions PacifiCorp paid on behalf of the NEOs, except for Mr. Bird and Ms. Crane for whom PacifiCorp also includes an amount paid to each of them as a tax gross-up with respect to a personal benefit with a value less than $10,000.

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

(5) Mr. Abel receives no direct compensation from PacifiCorp. PacifiCorp reimburses BHE for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. In 2017, PacifiCorp reimbursed BHE $123,480 for the cost of Mr. Abel's time spent on matters supporting PacifiCorp pursuant to the intercompany administrative services agreement.

(6) On January 10, 2018, Mr. Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and Mr. William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of PacifiCorp's NEOs as of December 31, 2017:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits (1)
Gregory E. Abel	n/a	n/a	n/a
Stefan A. Bird	Retirement	10 years	$ 177,225
Cindy A. Crane	Retirement	21 years	478,574
Nikki L. Kobliha	Retirement	12 years	123,795

(1) Amounts are computed using assumptions, other than the expected retirement age, consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K and are as of December 31, 2017, which is the measurement date for the plans. The expected retirement age assumption has been determined in accordance with Instruction 2 to Item 402 (h)(2) of Regulation S-K. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 60% lump sum payment; 40% joint and 100% survivor annuity if participant is married and 40% single life annuity if participant is single. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 3.60%; an expected retirement age of 65; postretirement mortality using the RP-2014 gender specific tables, adjusted for BHE credibility weighted experience, translated to 2011 using MP-2014. 2012 and 2013 rates were used for MP-2016 and MP-2017, respectively and generational mortality improvements from 2013 forward were based on the custom RPEC 2017 model; a lump sum interest rate of 3.60%; and lump sum mortality using the gender specific tables set forth in IRC 417(e)(3) for the upcoming fiscal year with mortality improvements determined using MP-2016.

Historically, PacifiCorp has adopted the Retirement Plan for the majority of its employees, other than employees subject to collective bargaining agreements that do not provide for coverage under the Retirement Plan. Through May 31, 2007, participants earned benefits at retirement payable for life based on length of service through May 31, 2007 and average pay in the 60 consecutive months of highest pay out of the 120 months prior to May 31, 2007. Pay for this purpose included base salary and annual incentive plan payments up to 10% of base salary, but was limited to the amounts specified in Internal Revenue Code Section 401(a)(17). Benefits were based on 1.3% of final average pay plus 0.65% of final average pay in excess of covered compensation (as defined in Internal Revenue Code Section 401(1)(5)(E)) multiplied by years of service.

The Retirement Plan was restated effective June 1, 2007 to change from a traditional final average pay formula as described above to a cash balance formula for non-union participants. Benefits under the final average pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on pay credits to each participant's account of 6.5% (5.0% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation. Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 received certain additional transition pay credits for five years from the effective date of the Retirement Plan restatement.

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

In 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan with any such election becoming effective January 1, 2009. Ms. Kobliha elected the equivalent fixed 401(k) contribution option and, therefore, no longer receives pay credits in the Retirement Plan. In 2017, the Retirement Plan was frozen for the remainder of the non-union employees (which include Mr. Bird and Ms. Crane) with pay credits equivalent to those received in the Retirement Plan allocated into the K Plus Employee Savings Plan. Each NEO continues to receive interest credits in the Retirement Plan.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of PacifiCorp's NEOs as of December 31, 2017:

Name	Executive contributions in 2017 (1)	Registrant contributions in 2017	Aggregate earnings in 2017	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2017 (2)
Gregory E. Abel	$ —	$ —	$ —	$ —	$ —
Stefan A. Bird	—	—	—	—	—
Cindy A. Crane	825,744	—	457,063	(85,811)	3,781,797
Nikki L. Kobliha	—	—	—	—	—

(1) The executive contribution amount shown for Ms. Crane represents a deferral of $500,000 of her 2017 compensation and $325,744 of her 2013 LTIP award which was deferred in 2017. The $500,000 deferred compensation and $100,751 of the deferred LTIP award are included in the 2017 total compensation reported for her in the Summary Compensation Table and are not additional compensation. The remaining 2013 LTIP award was earned prior to 2017.

(2) The aggregate balance as of December 31, 2017 shown for Ms. Crane includes $67,107 of compensation previously reported in 2016 in the Summary Compensation Table, and $35,397 of compensation previously reported in 2015 in the Summary Compensation Table.

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

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments, except in the case of the four DCP transition accounts that allow for a grandfathered payout based on the previous deferred compensation plan distribution elections of lump sum, 5, 10 or 15 annual installments. Effective December 31, 2006, no new money may be deferred into the DCP transition accounts. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55), all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

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

Potential Payments Upon Termination

PacifiCorp's NEOs, other than the Chairman and CEO, are not generally entitled to severance or enhanced benefits upon termination of employment or change in control. Mr. Abel resigned as PacifiCorp's Chairman and CEO on January 10, 2018 and received no severance or enhanced benefits in connection with his resignation.

The following table sets forth the estimated increase in the present value of benefits pursuant to the termination scenarios indicated for PacifiCorp's NEOs, other than Mr. Abel. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2017 and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive (1)	Pension (2)
Stefan A. Bird:		
Retirement, Voluntary and Involuntary With or Without Cause	—	49,531
Death and Disability	896,780	49,531
Cindy A. Crane(3):		
Involuntary With Cause	—	30,536
Retirement, Voluntary and Involuntary Without Cause, Death and Disability	974,072	30,536
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	1,282
Death and Disability	96,990	1,282

(1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested under certain circumstances.

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

(3) Ms. Crane has already met the retirement criteria, therefore her termination and death scenarios under the Retirement Plan are based on assuming 60% paid as a lump sum and 40% paid as a 100% joint and survivor annuity.

Chief Executive Officer Pay Ratio

PacifiCorp’s CEO receives no direct compensation from PacifiCorp, and no amounts are reported for the CEO in the Summary Compensation Table. Accordingly, PacifiCorp has determined that the CEO pay ratio is not calculable.

Director Compensation

PacifiCorp's directors do not receive additional compensation for service as directors of PacifiCorp. Compensation information for Messrs. Abel, Bird, Ms. Crane, and Ms. Kobliha for their services as executive officers of PacifiCorp is described above.

Compensation Committee Interlocks and Insider Participation

As of December 31, 2017, Mr. Abel was PacifiCorp's Chairman and CEO and also the Chairman, President and Chief Executive Officer of BHE. On January 10, 2018, Mr. Fehrman became PacifiCorp's Chairman and CEO and also the President and Chief Executive Officer of BHE. None of PacifiCorp's executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of PacifiCorp's Board of Directors. None of PacifiCorp's executive officers serves as a member of the board of directors of any company (other than BHE) that has an executive officer serving as a member of PacifiCorp's compensation committee. See also PacifiCorp's Item 13 in this Annual Report on Form 10-K.

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

BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

PACIFICORP

Beneficial Ownership

PacifiCorp is a consolidated subsidiary of BHE. PacifiCorp's common stock is indirectly owned by BHE, 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580. BHE is a consolidated subsidiary of Berkshire Hathaway that, as of February 16, 2018, owns 90.2% of BHE's common stock. The balance of BHE's common stock is beneficially owned by Walter Scott, Jr. (along with his family members and related or affiliated entities), a member of BHE's Board of Directors, and Gregory E. Abel, BHE's Executive Chairman.

None of PacifiCorp's executive officers or directors owns shares of its preferred stock. The following table sets forth certain information regarding the beneficial ownership of BHE's common stock and the Class A and Class B shares of Berkshire Hathaway common stock held by each of PacifiCorp's directors, executive officers and all of its directors and executive officers as a group as of February 16, 2018:

	BHE		Berkshire Hathaway			
	Common Stock		Class A Common Stock		Class B Common Stock	
Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)
William J. Fehrman	—	—	—	—	20	*
Stefan A. Bird	—	—	—	—	—	—
Cindy A. Crane	—	—	—	—	—	—
Patrick J. Goodman	—	—	5	*	786	*
Natalie L. Hocken	—	—	—	—	—	—
Nikki L. Kobliha	—	—	—	—	—	—
All executive officers and directors as a group (6 persons)	—	—	5	*	806	*

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

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

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

BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

PACIFICORP

Certain Relationships and Related Transactions

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

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

Under an intercompany administrative services agreement PacifiCorp has entered into with BHE and its other subsidiaries, the costs of certain administrative services provided by BHE to PacifiCorp or by PacifiCorp to BHE, or shared with BHE and other subsidiaries, are directly charged or allocated to the entity receiving such services. This agreement has been filed with the regulatory commissions in the states where PacifiCorp serves retail customers. PacifiCorp also provides an annual report of all transactions with its affiliates to its state regulatory commissions, who have the authority to refuse recovery in rates for payments PacifiCorp makes to its affiliates deemed to have the effect of subsidizing the separate business activities of BHE or its other subsidiaries.

Refer to Note 18 of the Notes to the Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for additional information regarding related-party transactions.

Director Independence

Because PacifiCorp's common stock is indirectly, wholly owned by BHE and its Board of Directors consists of BHE and PacifiCorp employees, PacifiCorp is not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

Based on the standards of the New York Stock Exchange LLC, on which the common stock of PacifiCorp's ultimate parent company, Berkshire Hathaway, is listed, PacifiCorp's Board of Directors has determined that none of its directors are considered independent because of their employment by BHE or PacifiCorp.

Item 14. Principal Accountant Fees and Services

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

	Berkshire Hathaway Energy	PacifiCorp	MidAmerican Funding	MidAmerican Energy	Nevada Power	Sierra Pacific
2017						
Audit fees(1)	$ 9.3	$ 1.5	$ 1.2	$ 1.1	$ 0.9	$ 0.9
Audit-related fees(2)	0.8	0.2	0.2	0.2	—	—
Tax fees(3)	0.1	—	—	—	—	—
Total	$ 10.2	$ 1.7	$ 1.4	$ 1.3	$ 0.9	$ 0.9
2016						
Audit fees(1)	$ 9.1	$ 1.5	$ 1.2	$ 1.1	$ 0.9	$ 1.1
Audit-related fees(2)	0.8	0.2	0.2	0.2	—	—
Tax fees(3)	0.1	—	—	—	—	—
Total	$ 10.0	$ 1.7	$ 1.4	$ 1.3	$ 0.9	$ 1.1

(1) Audit fees include fees for the audit of the consolidated financial statements and interim reviews of the quarterly financial statements for each Registrant, audit services provided in connection with required statutory audits of certain of BHE's subsidiaries and comfort letters, consents and other services related to SEC matters for each Registrant.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.

(3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal, state and international tax compliance, tax return preparation and tax audits.

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

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(1) Financial Statements

(2) Financial Statement Schedules

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

(b) Exhibits

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

Item 16. Form 10-K Summary

None.

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

	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 346	$ 33
Accounts receivable	—	21
Accounts receivable - affiliate	60	—
Notes receivable - affiliate	391	105
Other current assets	21	2
Total current assets	818	161
Investments in subsidiaries	34,019	33,400
Other investments	2,117	1,338
Goodwill	1,221	1,221
Other assets	1,155	1,171
Total assets	$ 39,330	$ 37,291
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 268	$ 357
Notes payable - affiliate	182	194
Short-term debt	3,331	834
Current portion of BHE senior debt	1,000	400
Total current liabilities	4,781	1,785
BHE senior debt	5,452	7,418
BHE junior subordinated debentures	100	944
Notes payable - affiliate	1	1,859
Other long-term liabilities	800	942
Total liabilities	11,134	12,948
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,368	6,390
Retained earnings	22,206	19,448
Accumulated other comprehensive loss, net	(398)	(1,511)
Total BHE shareholders' equity	28,176	24,327
Noncontrolling interest	20	16
Total equity	28,196	24,343
Total liabilities and equity	$ 39,330	$ 37,291

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

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Operations
For the years ended December 31,
(Amounts in millions)

	2017	2016	2015
Operating costs and expenses:			
General and administration	$ 55	$ 51	$ 58
Depreciation and amortization	4	4	3
Total operating costs and expenses	59	55	61
Operating loss	(59)	(55)	(61)
Other income (expense):			
Interest expense	(475)	(527)	(556)
Other, net	(369)	37	14
Total other income (expense)	(844)	(490)	(542)
Loss before income tax benefit and equity income	(903)	(545)	(603)
Income tax benefit	(335)	(285)	(330)
Equity income	3,441	2,805	2,646
Net income	2,873	2,545	2,373
Net income attributable to noncontrolling interest	3	3	3
Net income attributable to BHE shareholders	$ 2,870	$ 2,542	$ 2,370

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 Comprehensive Income
For the years ended December 31,
(Amounts in millions)

	2017	2016	2015
Net income	$ 2,873	$ 2,545	$ 2,373
Other comprehensive income (loss), net of tax	1,113	(603)	(414)
Comprehensive income	3,986	1,942	1,959
Comprehensive income attributable to noncontrolling interests	3	3	3
Comprehensive income attributable to BHE shareholders	$ 3,983	$ 1,939	$ 1,956

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 Cash Flows
For the years ended December 31,
(Amounts in millions)

	2017	2016	2015
Cash flows from operating activities	$ 2,450	$ 2,760	$ 2,528
Cash flows from investing activities:			
Investments in subsidiaries	(1,566)	(1,080)	(1,506)
Purchases of investments	(71)	(24)	(36)
Proceeds from sale of investments	68	20	47
Notes receivable from affiliate, net	(305)	(307)	19
Other, net	(8)	(5)	(7)
Net cash flows from investing activities	(1,882)	(1,396)	(1,483)
Cash flows from financing activities:			
Repayments of BHE senior debt	(1,379)	—	—
Repayments of BHE subordinated debt	(944)	(2,000)	(850)
Common stock purchases	(19)	—	(36)
Net proceeds from (repayments of) short-term debt	2,498	581	(142)
Tender offer premium paid	(406)	—	—
Notes payable to affiliate, net	—	69	4
Other, net	(5)	(4)	(1)
Net cash flows from financing activities	(255)	(1,354)	(1,025)
Net change in cash and cash equivalents	313	10	20
Cash and cash equivalents at beginning of year	33	23	3
Cash and cash equivalents at end of year	$ 346	$ 33	$ 23

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

BERKSHIRE HATHAWAY ENERGY COMPANY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Basis of Presentation - The condensed financial information of BHE investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in subsidiaries are recorded in the Condensed Balance Sheets. The income from operations of subsidiaries is reported on a net basis as equity income in the Condensed Statements of Operations.

Other investments - BHE's investment in BYD Company Limited ("BYD") common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of December 31, 2017 and 2016, the fair value of BHE's investment in BYD common stock was $1,961 million and $1,185 million, respectively, which resulted in an unrealized gain of $1,729 million and $953 million as of December 31, 2017 and 2016, respectively.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2017, 2016 and 2015 were $3.0 billion for each of the three years. In January and February 2018, BHE received cash dividends from its subsidiaries totaling $158 million.

Guarantees and commitments - BHE has issued guarantees up to a maximum of $236 million in support of various obligations of consolidated subsidiaries and commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $265 million.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures regarding long-term obligations (Notes 8, 9 and 10) and shareholders' equity (Note 17).

Schedule II

BERKSHIRE HATHAWAY ENERGY COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2017
(Amounts in millions)

Column A	Column B	Column C			Column E
	Balance at	Charged			Balance
	Beginning	to	Acquisition	Column D	at End
Description	of Year	Income	Reserves	Deductions	of Year
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectible accounts receivable:					
Year ended 2017	$ 33	$ 42	$ —	$ (35)	$ 40
Year ended 2016	31	39	—	(37)	33
Year ended 2015	37	33	—	(39)	31
Reserves Not Deducted From Assets[(1)]:					
Year ended 2017	$ 13	$ 7	$ —	$ (7)	$ 13
Year ended 2016	13	5	—	(5)	13
Year ended 2015	11	7	—	(5)	13

The notes to the consolidated BHE financial statements are an integral part of this financial statement schedule.

(1) Reserves not deducted from assets relate primarily to estimated liabilities for losses retained by BHE for workers compensation, public liability and property damage claims.

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2017	**2016**
ASSETS		
Current assets:		
Receivables from affiliates	$ 2	$ 2
Income tax receivable	13	—
Total current assets	15	2
Investments in and advances to subsidiaries	7,322	6,718
Total assets	$ 7,337	$ 6,720
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 6	$ 7
Payable to affiliate	431	301
Long-term debt	240	326
Total liabilities	677	634
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	4,981	4,407
Total member's equity	6,660	6,086
Total liabilities and member's equity	$ 7,337	$ 6,720

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

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Other income and (expense):			
Interest expense	$ (22)	$ (22)	$ (22)
Other, net	(30)	—	—
Loss before income taxes	(52)	(22)	(22)
Income tax benefit	(22)	(9)	(8)
Equity in undistributed earnings of subsidiaries	604	545	472
Net income	$ 574	$ 532	$ 458

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

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Net income	$ 574	$ 532	$ 458
Total other comprehensive income (loss), net of tax	—	3	(7)
Comprehensive income	$ 574	$ 535	$ 451

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

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Net cash flows from operating activities	$ (15)	$ (13)	$ (13)
Net cash flows from investing activities	—	—	—
Net cash flows from financing activities:			
Repayment of long-term debt	(86)	—	—
Tender offer premium paid	(29)	—	—
Net change in amounts payable to subsidiary	130	13	13
Net cash flows from financing activities	15	13	13
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$ —	$ —	$ —

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

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MidAmerican Funding, LLC and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2017 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Funding, LLC's ("MidAmerican Funding's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations.

Payable to Affiliate - MHC, Inc. ("MHC") settles all obligations of MidAmerican Funding including primarily interest costs on, and repayments of, MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $130 million, $13 million and $13 million for the years 2017, 2016 and 2015, respectively.

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

Schedule I

MHC INC.
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2017	**2016**
ASSETS		
Current assets:		
Cash and cash equivalents	$ —	$ 1
Receivables from affiliates	2	1
Receivable from parent	431	301
Investments and nonregulated property, net	14	12
Goodwill	1,270	1,270
Investments in and advances to subsidiaries	5,783	5,181
Total assets	$ 7,500	$ 6,766
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Payables to affiliates	$ 175	$ 44
Deferred income taxes	3	4
Total liabilities	178	48
Shareholder's equity:		
Paid-in capital	2,430	2,430
Retained earnings	4,892	4,288
Total shareholder's equity	7,322	6,718
Total liabilities and shareholder's equity	$ 7,500	$ 6,766

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

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Other income	$ 1	$ 1	$ 1
Income before income taxes	1	1	1
Equity in undistributed earnings of subsidiaries	603	544	471
Net income	$ 604	$ 545	$ 472

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

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Net income	$ 604	$ 545	$ 472
Total other comprehensive income (loss), net of tax	—	3	(7)
Comprehensive income	$ 604	$ 548	$ 465

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

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31, 2017	2016	2015
Net cash flows from operating activities	$ (1)	$ 1	$ 1
Net cash flows from investing activities:			
Dividend from subsidiary	—	—	16
Capital expenditures	(2)	(1)	—
Net change in amounts receivable from parent	(130)	(13)	(13)
Other	—	—	(1)
Net cash flows from investing activities	(132)	(14)	2
Net cash flows from financing activities:			
Net change in amounts payable to subsidiaries	(1)	5	(7)
Net change in note payable to Berkshire Hathaway Energy Company	133	9	3
Net cash flows from financing activities	132	14	(4)
Net change in cash and cash equivalents	(1)	1	(1)
Cash and cash equivalents at beginning of year	1	—	1
Cash and cash equivalents at end of year	$ —	$ 1	$ —

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

MHC INC.
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MHC Inc. and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2017, in Part IV, Item 15(c).

Basis of Presentation - The condensed financial information of MHC Inc.'s ("MHC's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations.

Receivable from Parent - MHC settles all obligations of MidAmerican Funding, LLC ("MidAmerican Funding") including primarily interest costs on, and repayments of, MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $130 million, $13 million and $13 million for the years 2017, 2016 and 2015, respectively.

Note Payable to Berkshire Hathaway Energy Company - On January 1, 2016, MidAmerican Energy Company transferred the assets and liabilities of its unregulated retail services business to a subsidiary of Berkshire Hathaway Energy Company ("BHE"). The transfer repaid $117 million of MHC's note payable to BHE. See Note 3 of MidAmerican Energy Company's Notes to Financial Statements in Part II, Item 8 for further discussion of the transfer.

See the notes to the consolidated MHC financial statements in Part IV, Item 15(c) for other disclosures.

Schedule II

MIDAMERICAN ENERGY COMPANY
VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2017
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Additions Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:				
Reserve for uncollectible accounts receivable:				
Year ended 2017	$ 7	$ 8	$ (8)	$ 7
Year ended 2016	$ 6	$ 7	$ (6)	$ 7
Year ended 2015	$ 7	$ 7	$ (8)	$ 6
Reserves Not Deducted From Assets[(1)]:				
Year ended 2017	$ 13	$ 7	$ (7)	$ 13
Year ended 2016	$ 13	$ 5	$ (5)	$ 13
Year ended 2015	$ 11	$ 7	$ (5)	$ 13

(1) Reserves not deducted from assets include estimated liabilities for losses retained by MidAmerican Energy for workers compensation, public liability and property damage claims.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
MHC INC. AND SUBSIDIARIES
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2017
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Additions Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:				
Reserve for uncollectible accounts receivable:				
Year ended 2017	$ 7	$ 8	$ (8)	$ 7
Year ended 2016	$ 6	$ 7	$ (6)	$ 7
Year ended 2015	$ 7	$ 7	$ (8)	$ 6
Reserves Not Deducted From Assets [(1)]:				
Year ended 2017	$ 13	$ 7	$ (7)	$ 13
Year ended 2016	$ 13	$ 5	$ (5)	$ 13
Year ended 2015	$ 11	$ 7	$ (5)	$ 13

(1) Reserves not deducted from assets include primarily estimated liabilities for losses retained by MidAmerican Funding and MHC for workers compensation, public liability and property damage claims.

The accompanying Consolidated Financial Statements of MHC Inc., the direct wholly owned subsidiary of MidAmerican Funding, are being provided pursuant to Rule 3-16 of the U. S. Securities and Exchange Commission's Regulation S-X. The purpose of these financial statements is to provide information about the assets and equity interests that collateralize MidAmerican Funding's long-term debt and that, upon the occurrence of any triggering event under the collateral agreement, would be available to satisfy the applicable debt obligations.

MHC Inc. and its subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MHC Inc.
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MHC Inc. and subsidiaries ("MHC") as of December 31, 2017 and 2016, 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, 2017, and the related notes and the schedules listed in the Index at Item 15(a)(ii) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of MHC as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MHC's management. Our responsibility is to express an opinion on MHC's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to MHC in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. MHC is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MHC’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 23, 2018

We have served as MHC's auditor since 1999.

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 172	$ 15
Receivables, net	346	284
Income taxes receivable	51	9
Inventories	245	264
Other current assets	135	35
Total current assets	949	607
Property, plant and equipment, net	14,221	12,835
Goodwill	1,270	1,270
Regulatory assets	204	1,161
Investments and restricted cash and investments	730	655
Receivable from affiliate	431	301
Other assets	233	216
Total assets	$ 18,038	$ 17,045

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2017	**2016**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 451	$ 302
Accrued interest	48	45
Accrued property, income and other taxes	133	138
Note payable to affiliate	164	31
Short-term debt	—	99
Current portion of long-term debt	350	250
Other current liabilities	128	159
Total current liabilities	1,274	1,024
Long-term debt	4,692	4,051
Deferred income taxes	2,235	3,568
Regulatory liabilities	1,661	883
Asset retirement obligations	528	510
Other long-term liabilities	326	291
Total liabilities	10,716	10,327
Commitments and contingencies (Note 15)		
Shareholder's equity:		
Common stock - no par value, 1,000 shares authorized, 1,000 shares issued and outstanding	—	—
Additional paid-in capital	2,430	2,430
Retained earnings	4,892	4,288
Total shareholder's equity	7,322	6,718
Total liabilities and shareholder's equity	$ 18,038	$ 17,045

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Operating revenue:			
Regulated electric	$ 2,108	$ 1,985	$ 1,837
Regulated gas and other	738	646	678
Total operating revenue	2,846	2,631	2,515
Operating costs and expenses:			
Cost of fuel, energy and capacity	434	410	433
Cost of gas sold and other	447	371	407
Operations and maintenance	784	693	707
Depreciation and amortization	500	479	407
Property and other taxes	119	112	110
Total operating costs and expenses	2,284	2,065	2,064
Operating income	562	566	451
Other income and (expense):			
Interest expense	(215)	(196)	(184)
Allowance for borrowed funds	15	8	8
Allowance for equity funds	41	19	20
Other, net	21	18	20
Total other income and (expense)	(138)	(151)	(136)
Income before income tax benefit	424	415	315
Income tax benefit	(180)	(130)	(141)
Income from continuing operations	604	545	456
Discontinued operations (Note 3):			
Income from discontinued operations	—	—	22
Income tax expense	—	—	6
Income on discontinued operations	—	—	16
Net income	$ 604	$ 545	$ 472

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2017	2016	2015
Net income	$ 604	$ 545	$ 472
Other comprehensive income (loss), net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $-, $1 and $-	—	3	—
Unrealized losses on cash flow hedges, net of tax of $-, $- and $(4)	—	—	(7)
Total other comprehensive income (loss), net of tax	—	3	(7)
Comprehensive income	$ 604	$ 548	$ 465

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Equity
Balance, December 31, 2014	$ 2,430	$ 3,272	$ (23)	$ 5,679
Net income	—	472	—	472
Other comprehensive loss	—	—	(7)	(7)
Balance, December 31, 2015	2,430	3,744	(30)	6,144
Net income	—	545	—	545
Other comprehensive income	—	—	3	3
Transfer to affiliate (Note 3)	—	—	27	27
Other equity transactions	—	(1)	—	(1)
Balance, December 31, 2016	2,430	4,288	—	6,718
Net income	—	604	—	604
Balance, December 31, 2017	$ 2,430	$ 4,892	$ —	$ 7,322

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income	$ 604	$ 545	$ 472
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	500	479	407
Deferred income taxes and amortization of investment tax credits	334	362	276
Changes in other assets and liabilities	37	47	49
Other, net	(57)	(92)	(70)
Changes in other operating assets and liabilities:			
Receivables, net	(61)	(61)	93
Inventories	19	(27)	(53)
Derivative collateral, net	2	5	33
Pension and other postretirement benefit plans, net	(11)	(6)	(8)
Accounts payable	69	39	(76)
Accrued property, income and other taxes, net	(42)	107	213
Other current assets and liabilities	1	8	12
Net cash flows from operating activities	1,395	1,406	1,348
Net cash flows from investing activities:			
Utility construction expenditures	(1,773)	(1,636)	(1,446)
Purchases of available-for-sale securities	(143)	(138)	(142)
Proceeds from sales of available-for-sale securities	137	158	135
Proceeds from sales of other investments	2	2	13
Net increase in restricted cash and investments	(98)	(10)	—
Net change in amounts receivable from parent	(130)	(13)	(13)
Other, net	(2)	10	2
Net cash flows from investing activities	(2,007)	(1,627)	(1,451)
Net cash flows from financing activities:			
Proceeds from long-term debt	990	62	649
Repayments of long-term debt	(255)	(38)	(426)
Net change in amounts receivable from/payable to affiliates	133	9	3
Net proceeds from (repayments of) short-term debt	(99)	99	(50)
Other, net	—	1	—
Net cash flows from financing activities	769	133	176
Net change in cash and cash equivalents	157	(88)	73
Cash and cash equivalents at beginning of year	15	103	30
Cash and cash equivalents at end of year	$ 172	$ 15	$ 103

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

MHC INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Company Organization

MHC Inc. ("MHC") is an Iowa corporation with MidAmerican Funding, LLC ("MidAmerican Funding") as its sole shareholder. MidAmerican Funding is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MHC constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations. Direct wholly owned nonregulated subsidiaries of MHC are Midwest Capital Group, Inc. and MEC Construction Services Co.

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for significant accounting policies of MHC.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MHC and its subsidiaries in which it held a controlling financial interest as of the date of the financial statement. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations. MHC has evaluated subsequent events through February 23, 2018, which is the date the Consolidated Financial Statements were issued.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MHC evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, MHC estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MHC uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings and regulatory asset value; and an appropriate discount rate. In estimating future cash flows, MHC incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2017, 2016 and 2015, MHC did not record any goodwill impairments.

(3) Discontinued Operations

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. The transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE repaid $117 million of MHC's note payable to BHE.

(4) Property, Plant and Equipment, Net

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's property, plant and equipment, net, MHC had gross nonregulated property of $24 million and $22 million as of December 31, 2017 and 2016, respectively, related accumulated depreciation and amortization of $10 million and $9 million as of December 31, 2017 and 2016, respectively, and construction work-in-progress of $1 million as of December 31, 2016, which consisted primarily of a corporate aircraft owned by MHC.

(5) Jointly Owned Utility Facilities

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(6) Regulatory Matters

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(7) Investments and Restricted Cash and Investments

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted cash and investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2017 and 2016.

(8) Short-Term Debt and Credit Facilities

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2018 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2017 and 2016, there were no borrowings outstanding under this credit facility. As of December 31, 2017, MHC was in compliance with the covenants of its credit facility.

(9) Long-Term Debt

Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(10) Income Taxes

Tax Cuts and Jobs Act

The Tax Cuts and Jobs Act enacted on December 22, 2017 (the "2017 Tax Reform") impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018 and limitations on bonus depreciation for utility property. Accounting principles generally accepted in the United States of America ("GAAP") require the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, MHC reduced deferred income tax liabilities $1,822 million. As it is probable the change in deferred taxes for MHC's regulated businesses will be passed back to customers through regulatory mechanisms, MHC increased net regulatory liabilities by $1,845 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. MHC has recorded the impacts of the 2017 Tax Reform and believes all the impacts to be complete with the exception of interpretations of the bonus depreciation rules. MHC has determined the amounts recorded and the interpretations relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. MHC believes its interpretations for bonus depreciation to be reasonable; however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

MHC's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2017	2016	2015
Current:			
Federal	$ (489)	$ (478)	$ (411)
State	(25)	(14)	(6)
	(514)	(492)	(417)
Deferred:			
Federal	338	367	282
State	(3)	(4)	(5)
	335	363	277
Investment tax credits	(1)	(1)	(1)
Total	$ (180)	$ (130)	$ (141)

A reconciliation of the federal statutory income tax rate to MHC's effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2017	2016	2015
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(68)	(60)	(67)
State income tax, net of federal income tax benefit	(4)	(3)	(2)
Effects of ratemaking	(7)	(3)	(12)
2017 Tax Reform	2	—	—
Other, net	(1)	—	1
Effective income tax rate	(43)%	(31)%	(45)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Interim recognition of production tax credits in income is based on the annualized effective tax rate applied each period, similar to all book to tax differences. Recognition of production tax credits in income during interim periods of the year may vary significantly from actual amounts earned. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

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

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 443	$ 333
Asset retirement obligations	160	230
Employee benefits	45	66
Other	62	82
Total deferred income tax assets	710	711
Deferred income tax liabilities:		
Depreciable property	(2,868)	(3,767)
Regulatory assets	(42)	(471)
Other	(35)	(41)
Total deferred income tax liabilities	(2,945)	(4,279)
Net deferred income tax liability	$ (2,235)	$ (3,568)

As of December 31, 2017, MHC has available $40 million of state tax carryforwards, principally related to $583 million of net operating losses, that expire at various intervals between 2018 and 2036.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 31, 2009, including components related to MHC. In addition, state jurisdictions have closed their examinations of MidAmerican Energy's income tax returns for Iowa through December 31, 2013, for Illinois through December 31, 2008, and for other jurisdictions through December 31, 2009.

A reconciliation of the beginning and ending balances of MHC's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2017	2016
Beginning balance	$ 10	$ 10
Additions based on tax positions related to the current year	1	—
Additions for tax positions of prior years	23	10
Reductions based on tax positions related to the current year	(4)	(2)
Reductions for tax positions of prior years	(19)	(8)
Interest and penalties	1	—
Ending balance	$ 12	$ 10

As of December 31, 2017, MHC had unrecognized tax benefits totaling $39 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MHC's effective income tax rate.

(11) Employee Benefit Plans

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MHC's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MHC to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2017	2016	2015
Pension costs	$ 4	$ 4	$ 4
Other postretirement costs	(3)	(1)	(2)

(12) Asset Retirement Obligations

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(13) Risk Management and Hedging Activities

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(14) Fair Value Measurements

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(15) Commitments and Contingencies

Refer to Note 15 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

Legal Matters

MHC is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MHC does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(16) Components of Accumulated Other Comprehensive Loss, Net

Refer to Note 16 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2017	2016	2015
Corporate-owned life insurance income	$ 13	$ 8	$ 4
Gain on redemption of auction rate securities	—	5	—
Gains on sales of assets and other investments	1	3	13
Interest income and other, net	7	2	3
Total	$ 21	$ 18	$ 20

MidAmerican Funding recognized a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

(18) Supplemental Cash Flow Information

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

	2017	2016	2015
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 193	$ 181	$ 154
Income taxes received, net	$ 463	$ 600	$ 621
Supplemental disclosure of non-cash investing and financing transactions:			
Accounts payable related to utility plant additions	$ 224	$ 131	$ 249
Transfer of assets and liabilities to affiliate (note 3)	$ —	$ 90	$ —

(19) Related Party Transactions

The companies identified as affiliates of MHC are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MHC and the affiliates.

MHC is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $46 million, $35 million and $35 million for 2017, 2016 and 2015, respectively.

MHC reimbursed BHE in the amount of $7 million, $6 million and $7 million in 2017, 2016 and 2015, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $122 million, $135 million and $165 million in 2017, 2016 and 2015, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $164 million at an interest rate of 1.629% as of December 31, 2017, and $31 million at an interest rate of 0.885% as of December 31, 2016, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2017 and 2016.

MHC settles all obligations of MidAmerican Funding including primarily interest costs on MidAmerican Funding's long-term debt. In 2017, MHC paid for MidAmerican Funding's redemption of a portion of its long-term debt through a tender offer. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $130 million, $13 million and $13 million for 2017, 2016 and 2015, respectively.

MHC had accounts receivable from affiliates of $438 million and $306 million as of December 31, 2017 and 2016, respectively, that are reflected in receivables, net and receivable from affiliate on the Consolidated Balance Sheets. MHC also had accounts payable to affiliates of $14 million and $12 million as of December 31, 2017 and 2016, respectively, that are included in accounts payable on the Consolidated Balance Sheets.

MHC is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated United States federal income tax return. For current federal and state income taxes, MHC had a receivable from BHE of $51 million as of December 31, 2017, and a payable to BHE of $7 million as of December 31, 2016. MHC received net cash receipts for federal and state income taxes from BHE totaling $463 million, $600 million and $621 million for the years ended December 31, 2017, 2016 and 2015, respectively.

MHC recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MHC's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MHC adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $16 million and $12 million as of December 31, 2017 and 2016, respectively, and similar amounts payable to affiliates totaled $45 million and $36 million, as of December 31, 2017 and 2016, respectively. See Note 11 for further information pertaining to pension and postretirement accounting.

(20) Segment Information

MHC has identified two reportable operating segments: regulated electric and regulated gas. The previously reported nonregulated energy segment consisted substantially of MidAmerican Energy's unregulated retail services business, which was transferred to a subsidiary of BHE and is excluded from the information below related to the statements of operations for all periods presented. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists principally of the nonregulated subsidiaries of MHC not engaged in the energy business. Refer to Note 10 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2017	2016	2015
Operating revenue:			
Regulated electric	$ 2,108	$ 1,985	$ 1,837
Regulated gas	719	637	661
Other	19	9	17
Total operating revenue	$ 2,846	$ 2,631	$ 2,515
Depreciation and amortization:			
Regulated electric	$ 458	$ 436	$ 366
Regulated gas	42	43	41
Total depreciation and amortization	$ 500	$ 479	$ 407
Operating income:			
Regulated electric	$ 485	$ 497	$ 385
Regulated gas	77	68	64
Other	—	1	2
Total operating income	$ 562	$ 566	$ 451
Interest expense:			
Regulated electric	$ 196	$ 178	$ 166
Regulated gas	18	18	17
Other	1	—	1
Total interest expense	$ 215	$ 196	$ 184
Income tax (benefit) expense from continuing operations:			
Regulated electric	$ (212)	$ (156)	$ (163)
Regulated gas	29	22	16
Other	3	4	6
Total income tax (benefit) expense from continuing operations	$ (180)	$ (130)	$ (141)
Net income:			
Regulated electric	$ 570	$ 512	$ 413
Regulated gas	35	32	33
Other	(1)	1	10
Income from continuing operations	604	545	456
Income on discontinued operations	—	—	16
Net income	$ 604	$ 545	$ 472
Utility construction expenditures:			
Regulated electric	$ 1,686	$ 1,564	$ 1,365
Regulated gas	87	72	81
Total utility construction expenditures	$ 1,773	$ 1,636	$ 1,446

	As of December 31,		
	2017	2016	2015
Total assets:			
Regulated electric	$ 16,105	$ 15,304	$ 14,161
Regulated gas	1,482	1,424	1,330
Other	451	317	468
Total assets	$ 18,038	$ 17,045	$ 15,959

Goodwill by reportable segment as of December 31, 2017 and 2016 was as follows (in millions):

Regulated electric	$ 1,191
Regulated gas	79
Total	$ 1,270

EXHIBIT INDEX

BERKSHIRE HATHAWAY ENERGY

3.1	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Articles of Amendment to the Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective April 30, 2014 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
3.3	Amended and Restated Bylaws of Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 3.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.1	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.3	Indenture, dated as of November 12, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the Junior Subordinated Debentures due 2044 (including form of junior subordinated debenture) (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated December 1, 2014).
4.4	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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 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).
4.10	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).

Exhibit No.	Description
4.11	Eleventh Supplemental Indenture, dated as of December 29, 2017, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 6.500% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).
4.12	Twelfth Supplemental Indenture, dated as of January 5, 2018, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 2.375% Senior Notes due 2021, the 2.800% Senior Notes due 2023, the 3.250% Senior Notes due 2028 and the 3.800% Senior Notes due 2048 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).
4.13	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated October 23, 1997).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.21	First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.22	Third Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Electricity Distribution plc, Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9.25% Bonds due 2020 (incorporated by reference to Exhibit 10.76 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

Exhibit No.	Description
4.23	First Supplemental Trust Deed, dated as of September 27, 2001, among Northern Electric Finance plc, Northern Electric plc, Northern Electric Distribution Limited and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.81 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.24	Trust Deed, dated as of January 17, 1995, by and between Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9 1/4% Bonds due 2020 (incorporated by reference to Exhibit 10.83 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.25	Master Trust Deed, dated as of October 16, 1995, by and between Northern Electric Finance plc, Northern Electric plc and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.70 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.26	Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.27	Reimbursement and Indemnity Agreement, dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.28	Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.29	Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.30	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.31	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.32	£119,000,000 Finance Contract, dated July 2, 2010, by and between Northern Electric Distribution Limited and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.33	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.34	£151,000,000 Finance Contract, dated July 2, 2010, by and between Yorkshire Electricity Distribution plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.35	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).

Exhibit No.	Description
4.36	Trust Deed, dated as of July 5, 2012, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 4.375% Bonds due 2032 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).
4.37	Trust Deed, dated as of April 1, 2015, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.50% Bonds due 2025 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.38	£120,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Northeast) Ltd 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, 2016).
4.39	Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings 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, 2016).
4.40	£130,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Yorkshire) 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, 2016).
4.41	Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings 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, 2016).
4.42	Deed of Amendment and Consent, dated March 1, 2016, by and between Northern Powergrid Holdings Company, Northern Powergrid (Yorkshire) plc and the European Investment Bank (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.43	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).
4.44	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).
4.45	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and The Bank of New York Trust Company, N.A., Fiscal Agent, relating to the $150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated February 12, 2007).
4.46	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).
4.47	Master Trust Indenture, dated November 21, 2005, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.94 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
4.48	Third Supplemental Indenture, dated December 15, 2010, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.96 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.49	Series 12-1 Supplemental Indenture, dated June 5, 2012, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.97 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.50	Series 13-1 Supplemental Indenture, dated April 9, 2013, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.98 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.51	Series 15-1 Supplemental Indenture, dated March 6, 2015, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada, relating to C$200,000,000 in principal amount of the 2.244% Series 15-1 Senior Bonds due 2022 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.52	2016 Supplemental Indenture, dated December 9, 2016, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.53 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
4.53	Amended and Restated Master Trust Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.99 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.54	Seventh Supplemental Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.100 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.55	Ninth Supplemental Indenture, dated May 9, 2006, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.101 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.56	Tenth Supplemental Indenture, dated May 21, 2008, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.102 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.57	Twelfth Supplemental Indenture, dated August 18, 2010, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.103 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.58	Sixteenth Supplemental Indenture, dated November 15, 2012, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.104 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.59	Seventeenth Supplemental Indenture, dated May 22, 2013, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.105 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.60	Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.106 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
4.61	Nineteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.107 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.62	Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to C$350,000,000 in principal amount of the 4.09% Series 2015-1 Medium-Term Notes due 2045 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2015).
4.63	Indenture, dated as of February 24, 2012, by and between Topaz Solar Farms LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $850,000,000 in principal amount of the 5.75% Series A Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.56 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).
4.64	First Supplemental Indenture, dated as of April 15, 2013, between Topaz Solar Farms LLC, as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $250,000,000 in principal amount of the 4.875% Series B Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.65	Indenture, dated as of June 27, 2013, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $1,000,000,000 in principal amount of the 5.375% Series A Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.66	First Supplemental Indenture, dated as of March 12, 2015, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $325,000,000 in principal amount of the 3.95% Series B Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
10.1	$2,000,000,000 Credit Agreement, dated as of June 30, 2016, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, MUFG Union Bank, N.A., as Administrative Agent, 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, 2016).
10.2	$1,000,000,000 Credit Agreement, dated as of May 11, 2017, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, and The Bank of Tokyo-Mitsubishi UFJ, LTD., as Administrative Agent (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, 2017).
10.3	Amended and Restated £150,000,000 Facility Agreement, dated April 30, 2015, among Northern Powergrid Holdings Company, as Guarantor and Borrower, Northern Powergrid (Yorkshire) plc and Northern Powergrid (Northeast) Limited as Borrowers, and Abbey National Treasury Services plc, Lloyds Bank plc and The Royal Bank of Scotland plc, as Original Lenders (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.4	Amended and Restated Credit Agreement, dated as of July 30, 2015, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.5	First Amending Agreement to Amended and Restated Credit Agreement, dated as of November 20, 2015, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).

Exhibit No.	Description
10.6	Second Amending Agreement to Amended and Restated Credit Agreement, dated as of December 14, 2015, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.7	Third Amending Agreement to Amended and Restated Credit Agreement, dated as of July 8, 2016, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.8	Fourth Amending Agreement to Amended and Restated Credit Agreement, dated as of December 15, 2016, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.7 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
10.9	Fifth Amending Agreement to Amended and Restated Credit Agreement, dated as of December 15, 2017, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders.
10.10	Credit Agreement, dated as of December 9, 2016, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.8 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
10.11	First Amending Agreement to Credit Agreement, dated as of December 8, 2017, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Bank of Montreal, as administrative agent, and Lenders.
10.12	Fourth Amended and Restated Credit Agreement, dated as of December 17, 2015, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.8 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.13	First Amending Agreement to Fourth Amended and Restated Credit Agreement, dated as of December 15, 2016, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.10 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
10.14	Second Amending Agreement to Fourth Amended and Restated Credit Agreement, dated as of December 14, 2017, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.15	Third Amended and Restated Credit Agreement, dated as of December 17, 2015, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.7 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.16	First Amending Agreement to Third Amended and Restated Credit Agreement, dated as of December 15, 2016, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.12 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
10.17	Second Amending Agreement to Third Amended and Restated Credit Agreement, dated as of December 14, 2017, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.18*	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2014 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
14.1	Berkshire Hathaway Energy 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, 2015).
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.

PACIFICORP

3.4	Third Restated Articles of Incorporation of PacifiCorp (incorporated by reference to Exhibit (3)a to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 1996).
3.5	Bylaws of PacifiCorp, as amended May 23, 2005 (incorporated by reference to Exhibit 3.2 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.19*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.20*	PacifiCorp Executive Voluntary Deferred Compensation Plan (incorporated by reference to Exhibit 10.3 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2007).
10.21*	Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.22*	Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.23*	Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.6 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.24*	Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2009).
10.25*	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012 (incorporated by reference to Exhibit 10.11 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2012).
10.26*	PacifiCorp Long-Term Incentive Partnership Plan effective January 1, 2014 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2014).
12.1	Statements of Computation of Ratio of Earnings to Fixed Charges.
12.2	Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
14.2	Code of Ethics (incorporated by reference to Exhibit 14.1 to the PacifiCorp Transition Report on Form 10-K for the nine-month period ended December 31, 2006).
23.2	Consent of Deloitte & Touche LLP.
31.3	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.3	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
32.4	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.67 Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, incorporated by reference to Exhibit 4-E to the PacifiCorp Form 8-B, as supplemented and modified by 28 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp File Type	File Date
(4)(b)[(a)]	SE	November 2, 1989
(4)(a)[(a)]	8-K	January 9, 1990
(4)(a)[(a)]	8-K	September 11, 1991
(4)(a)[(a)]	8-K	January 7, 1992
(4)(a)[(a)]	10-Q	Quarter ended March 31, 1992
(4)(a)[(a)]	10-Q	Quarter ended September 30, 1992
(4)(a)[(a)]	8-K	April 1, 1993
(4)(a)[(a)]	10-Q	Quarter ended September 30, 1993
(4)b	10-Q	Quarter ended June 30, 1994
(4)b	10-K	Year ended December 31, 1994
(4)b	10-K	Year ended December 31, 1995
(4)b	10-K	Year ended December 31, 1996
(4)b	10-K	Year ended December 31, 1998
99(a)	8-K	November 21, 2001
4.1	10-Q	Quarter ended June 30, 2003
99	8-K	September 9, 2003
4	8-K	August 26, 2004
4	8-K	June 14, 2005
4.2	8-K	August 14, 2006
4	8-K	March 14, 2007
4.1	8-K	October 3, 2007
4.1	8-K	July 17, 2008
4.1	8-K	January 8, 2009
4.1	8-K	May 12, 2011
4.1	8-K	January 6, 2012
4.1	8-K	June 6, 2013
4.1	8-K	March 13, 2014
4.1	8-K	June 19, 2015

10.27	$400,000,000 Credit Agreement, dated as of June 30, 2016, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent, and the LC Issuing Banks (incorporated by reference to Exhibit 10.9 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.28	$600,000,000 Credit Agreement, dated as of June 30, 2017, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent, and the LC Issuing Banks (incorporated by reference to Exhibit 10.2 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Exhibit No.	Description
MIDAMERICAN ENERGY	
3.6	Restated Articles of Incorporation of MidAmerican Energy Company, as amended October 27, 1998. (incorporated by reference to Exhibit 3.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
3.7	Restated Bylaws of MidAmerican Energy Company, as amended July 24, 1996. (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 1996).
14.3	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
23.3	Consent of Deloitte & Touche LLP.
31.5	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.6	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.5	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.6	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
MIDAMERICAN FUNDING	
3.8	Articles of Organization of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.1 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.9	Operating Agreement of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.2 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.10	Amendment No. 1 to the Operating Agreement of MidAmerican Funding, LLC dated as of February 9, 2010 (incorporated by reference to Exhibit 3.3 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2009).
14.4	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (incorporated by reference to Exhibit 14.2 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2003).
31.7	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.8	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.7	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.8	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN ENERGY AND MIDAMERICAN FUNDING	
4.68	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).
4.69	First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.70	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).

Exhibit No.	Description
4.71	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).
4.72	First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.80% Notes due 2036 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.73	Third Supplemental Indenture, dated March 25, 2008, by and between MidAmerican Energy Company and The Bank of New York Trust Company, Trustee, relating to the 5.30% Notes due 2018 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated March 25, 2008).
4.74	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).
4.75	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).
4.76	Specimen of 2.40% First Mortgage Bonds due 2019 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.77	Specimen of 3.70% First Mortgage Bonds due 2023 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.78	Specimen of 4.80% First Mortgage Bonds due 2043 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.79	Amendment No. 1 to the First Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.80	Second Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.81	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.82	Specimen of 4.40% First Mortgage Bonds due 2044 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.83	Amendment No. 1 to the Second Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.84	Third Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.85	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.86	Specimen of 4.25% First Mortgage Bonds due 2046 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.87	Fourth Supplemental Indenture, dated as of December 8, 2016, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.96 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).

Exhibit No.	Description
4.88	Fifth Supplemental Indenture, dated as of February 1, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.89	Specimen of 3.10% First Mortgage Bonds due 2027 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.90	Specimen of 3.95% First Mortgage Bonds due 2047 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.91	Sixth Supplemental Indenture, dated as of December 14, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013.
4.92	Seventh Supplemental Indenture, dated as of February 1, 2018, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2018).
4.93	Specimen of 3.65% First Mortgage Bonds due 2048 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2018).
4.94	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).
4.95	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).
4.96	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Senior Unsecured Debt Securities) (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
4.97	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Subordinated Unsecured Debt Securities) (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
10.29	$900,000,000 Credit Agreement, dated as of June 30, 2017, among MidAmerican Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Mizuho Bank, Ltd., as Administrative Agent, and the LC Issuing Banks (incorporated by reference to Exhibit 10.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

4.98	Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the $325 million Senior Bonds (incorporated by reference to Exhibits 4.1 and 4.2 to the MidAmerican Funding, LLC Registration Statement No. 333-905333 dated November 8, 1999).

NEVADA POWER

3.11	Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (incorporated by reference to Exhibit 3(B) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).
3.12	Amended and Restated By-Laws of Nevada Power Company dated July 28, 1999 (incorporated by reference to Exhibit 3(C) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).

Exhibit No.	Description
4.99	Financing Agreement dated May 1, 2017 between Clark County, Nevada and Nevada Power Company (relating to Clark County, Nevada's $39,500,000 Pollution Control Refunding Revenue Bonds (Nevada Power Company Project) Series 2017) (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).
4.100	Financing Agreement dated May 1, 2017 between the Coconino County, Arizona Pollution Control Corporation and Nevada Power Company (relating to the Coconino County, Arizona Pollution Control Corporation's $53,000,000 Pollution Control Refunding Revenue Bonds (Nevada Power Company Projects) Series 2017A and 2017B) (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).
10.30	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
12.3	Computation of Ratios of Earnings to Fixed Charges.
14.5	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
23.4	Consent of Deloitte & Touche LLP.
31.9	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.10	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.9	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.10	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER

4.101	General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.1(a) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.102	First Supplemental Indenture, dated as of May 1, 2001 (incorporated by reference to Exhibit 4.1(b) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.103	Second Supplemental Indenture, dated as of October 1, 2001 (incorporated by reference to Exhibit 4(A) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2001).
4.104	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).
4.105	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).
4.106	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).
4.107	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).
4.108	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).
4.109	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).

Exhibit No.	Description
4.110	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).
4.111	Officer’s Certificate establishing the terms of Nevada Power Company’s General and Refunding Mortgage Notes, Series AA (Nos. AA-1 and AA-2) (incorporated by reference to Exhibit 4.3 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).
10.31	$400,000,000 Second 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 10.4 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
SIERRA PACIFIC	
3.13	Restated Articles of Incorporation of Sierra Pacific Power Company, dated October 25, 2006 (incorporated by reference to Exhibit 3.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for quarter ended September 30, 2006).
3.14	By-Laws of Sierra Pacific Power Company, as amended through November 13, 1996 (incorporated by reference to Exhibit (3)(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 1996).
4.112	Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's $80,000,000 Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016C, 2016D and 2016E (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
4.113	Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's $213,930,000 Gas Facilities Refunding Revenue Bonds, Gas and Water Facilities Refunding Revenue Bonds and Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Projects) Series 2016A, 2016B, 2016F and 2016G (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
4.114	Financing Agreement dated May 1, 2016 between Humboldt County, Nevada and Sierra Pacific Power Company (relating to Humboldt County, Nevada's $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016A and 2016B (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
10.32	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
12.4	Computation of Ratios of Earnings to Fixed Charges.
14.6	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
31.11	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.12	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.11	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.12	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
	BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC
4.115	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).
4.116	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).
4.117	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).
4.118	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).
4.119	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 2.60% General and Refunding Mortgage Notes, Series U, due 2026 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated April 15, 2016).
4.120	Officer's Certificate establishing the terms of Sierra Pacific Power Company's General and Refunding Mortgage Notes, Series V (Nos. V-1, V-2 and V-3) (incorporated by reference to Exhibit 4.4 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
10.33	$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 10.5 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
	ALL REGISTRANTS
101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2017 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.

(a) Not available electronically on the SEC website as it was filed in paper previous to the electronic system currently in place.

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, each Registrant has not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt not registered in which the total amount of securities authorized thereunder does not exceed 10% of the total assets of the respective Registrant. Each Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

SIGNATURES

BERKSHIRE HATHAWAY ENERGY COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 23rd day of February 2018.

BERKSHIRE HATHAWAY ENERGY COMPANY

/s/ William J. Fehrman*

William J. Fehrman
Director, 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/ William J. Fehrman* William J. Fehrman	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2018
/s/ Patrick J. Goodman* Patrick J. Goodman	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2018
/s/ Gregory E. Abel* Gregory E. Abel	Executive Chairman of the Board of Directors	February 23, 2018
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 23, 2018
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 23, 2018
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	February 23, 2018
*By: /s/ Natalie L. Hocken Natalie L. Hocken	Attorney-in-Fact	February 23, 2018

SIGNATURES

PACIFICORP

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 23rd day of February 2018.

PACIFICORP

/s/ Nikki L. Kobliha

Nikki L. Kobliha

Director, Vice President, Chief Financial Officer and Treasurer

(principal financial and accounting officer)

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

Signature	Title	Date
/s/ William J. Fehrman William J. Fehrman	Chairman of the Board of Directors, President and Chief Executive Officer (principal executive officer)	February 23, 2018
/s/ Nikki L. Kobliha Nikki L. Kobliha	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 23, 2018
/s/ Stefan A. Bird Stefan A. Bird	Director	February 23, 2018
/s/ Cindy A. Crane Cindy A. Crane	Director	February 23, 2018
/s/ Patrick J. Goodman Patrick J. Goodman	Director	February 23, 2018
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 23, 2018

SIGNATURES

MIDAMERICAN ENERGY COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 23rd day of February 2018.

MIDAMERICAN ENERGY COMPANY

/s/ Adam L. Wright

Adam L. Wright
Director, President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Adam L. Wright Adam L. Wright	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2018
/s/ Thomas B. Specketer Thomas B. Specketer	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2018
/s/ Robert B. Berntsen Robert B. Berntsen	Director	February 23, 2018

SIGNATURES

MIDAMERICAN FUNDING, LLC

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 23rd day of February 2018.

MIDAMERICAN FUNDING, LLC

/s/ Adam L. Wright

Adam L. Wright
Manager and President
(principal executive officer)

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

Signature	Title	Date
/s/ Adam L. Wright Adam L. Wright	Manager and President (principal executive officer)	February 23, 2018
/s/ Thomas B. Specketer Thomas B. Specketer	Vice President and Controller (principal financial and accounting officer)	February 23, 2018
/s/ Daniel S. Fick Daniel S. Fick	Manager	February 23, 2018
/s/ Patrick J. Goodman Patrick J. Goodman	Manager	February 23, 2018
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 23, 2018

SIGNATURES

NEVADA POWER COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 23rd day of February 2018.

NEVADA POWER COMPANY

/s/ Paul J. Caudill

Paul J. Caudill
Director and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	Director and Chief Executive Officer (principal executive officer)	February 23, 2018
/s/ E. Kevin Bethel E. Kevin Bethel	Director, Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2018
/s/ Douglas A. Cannon Douglas A. Cannon	Director	February 23, 2018
/s/ Patrick S. Egan Patrick S. Egan	Director	February 23, 2018
/s/ Shawn M. Elicegui Shawn M. Elicegui	Director	February 23, 2018
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 23, 2018
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 23, 2018

SIGNATURES

SIERRA PACIFIC POWER COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 23rd day of February 2018.

SIERRA PACIFIC POWER COMPANY

/s/ Paul J. Caudill

Paul J. Caudill
Director and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	Director and Chief Executive Officer (principal executive officer)	February 23, 2018
/s/ E. Kevin Bethel E. Kevin Bethel	Director, Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2018
/s/ Douglas A. Cannon Douglas A. Cannon	Director	February 23, 2018
/s/ Patrick S. Egan Patrick S. Egan	Director	February 23, 2018
/s/ Shawn M. Elicegui Shawn M. Elicegui	Director	February 23, 2018
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 23, 2018
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 23, 2018

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report to security holders covering each respective Registrant's last fiscal year or proxy material has been sent to security holders.

EXHIBIT 12.1

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

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,128	$ 1,103	$ 1,023	$ 1,007	$ 979
Fixed charges	386	385	384	384	385
Total earnings available for fixed charges	$ 1,514	$ 1,488	$ 1,407	$ 1,391	$ 1,364
Fixed Charges:					
Interest expense	$ 381	$ 380	$ 379	$ 379	$ 379
Estimated interest portion of rentals charged to expense	5	5	5	5	6
Total fixed charges	$ 386	$ 385	$ 384	$ 384	$ 385
Ratio of Earnings to Fixed Charges	3.9x	3.9x	3.7x	3.6x	3.5x

EXHIBIT 12.2

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

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,128	$ 1,103	$ 1,023	$ 1,007	$ 979
Fixed charges	386	385	384	384	385
Total earnings available for fixed charges	$ 1,514	$ 1,488	$ 1,407	$ 1,391	$ 1,364
Fixed Charges and Preferred Stock Dividends:					
Interest expense	$ 381	$ 380	$ 379	$ 379	$ 379
Estimated interest portion of rentals charged to expense	5	5	5	5	6
Total fixed charges	386	385	384	384	385
Preferred stock dividends [(1)]	—	—	—	—	2
Total fixed charges and preferred stock dividends	$ 386	$ 385	$ 384	$ 384	$ 387
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.9x	3.9x	3.7x	3.6x	3.5x

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

EXHIBIT 12.3

NEVADA POWER COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings available for fixed charges:					
Net income	$ 255	$ 279	$ 288	$ 227	$ 145
Add (deduct):					
Income tax expense	156	146	162	130	94
Fixed charges	179	185	190	211	220
Capitalized interest (allowance for borrowed funds used during construction)	(1)	(4)	(3)	(1)	(6)
	334	327	349	340	308
Total earnings available for fixed charges	$ 589	$ 606	$ 637	$ 567	$ 453
Fixed charges -					
Interest expense	179	185	190	211	220
Total fixed charges	$ 179	$ 185	$ 190	$ 211	$ 220
Ratio of earnings to fixed charges	3.3x	3.3x	3.4x	2.7x	2.1x

EXHIBIT 12.4

SIERRA PACIFIC POWER COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Millions)

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Earnings available for fixed charges:					
Net income	$ 109	$ 84	$ 83	$ 87	$ 55
Add (deduct):					
Income tax expense	55	49	47	47	33
Fixed charges	43	56	61	63	62
Capitalized interest (allowance for borrowed funds used during construction)	(2)	(4)	(2)	(2)	(2)
	96	101	106	108	93
Total earnings available for fixed charges	$ 205	$ 185	$ 189	$ 195	$ 148
Fixed charges -					
Interest expense	43	56	61	63	62
Total fixed charges	$ 43	$ 56	$ 61	$ 63	$ 62
Ratio of earnings to fixed charges	4.8x	3.3x	3.1x	3.1x	2.4x

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	Nevada
Sierra Pacific Power Company	Nevada
Northern Powergrid Holdings Company	United Kingdom
Northern Powergrid UK Holdings	United Kingdom
Northern Powergrid Limited	United Kingdom
Northern Electric plc.	United Kingdom
Northern Powergrid (Northeast) Limited	United Kingdom
Yorkshire Power Group Limited	United Kingdom
Yorkshire Electricity Group plc.	United Kingdom
Northern Powergrid (Yorkshire) plc.	United Kingdom
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	Canada
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. 333-214946 on Form S-8 of our report dated February 23, 2018, 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, 2017.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 23, 2018

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-207687 on Form S-3 of our report dated February 23, 2018, relating to the consolidated financial statements of PacifiCorp and subsidiaries appearing in this Annual Report on Form 10-K of PacifiCorp for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2018

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206980 on Form S-3 of our report dated February 23, 2018, relating to the financial statements and financial statement schedule of MidAmerican Energy Company (which report expresses an unqualified opinion), appearing in this Annual Report on Form 10-K of MidAmerican Energy Company for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 23, 2018

EXHIBIT 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-213897 on Form S-3 of our report dated February 23, 2018 relating to the consolidated financial statements of Nevada Power Company and subsidiaries appearing in this Annual Report on Form 10-K of Nevada Power Company for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 23, 2018

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 Natalie L. Hocken 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, 2017 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 23, 2018

/s/ William J. Fehrman
WILLIAM J. FEHRMAN

/s/ Patrick J. Goodman
PATRICK J. GOODMAN

/s/ Gregory E. Abel
GREGORY E. ABEL

/s/ Warren E. Buffett
WARREN E. BUFFETT

/s/ Marc D. Hamburg
MARC D. HAMBURG

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

EXHIBIT 31.1

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

I, William J. Fehrman, 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 23, 2018

/s/ William J. Fehrman
William J. Fehrman
Director, 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 23, 2018

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

EXHIBIT 31.3

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

I, William J. Fehrman, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ William J. Fehrman
William J. Fehrman
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.4

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

I, Nikki L. Kobliha, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Director, Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 31.5

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

I, Adam L. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Energy Company;

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Adam L. Wright
Adam L. Wright
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.6

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

I, Thomas B. Specketer, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Energy Company;

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.7

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

I, Adam L. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Funding, LLC;

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Adam L. Wright
Adam L. Wright
President
(principal executive officer)

EXHIBIT 31.8

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

I, Thomas B. Specketer, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Funding, LLC;

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 31.9

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

I, Paul J. Caudill, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Paul J. Caudill
Paul J. Caudill
Director and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.10

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

I, E. Kevin Bethel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ E. Kevin Bethel
E. Kevin Bethel
Director, Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.11

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

I, Paul J. Caudill, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ Paul J. Caudill
Paul J. Caudill
Director and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.12

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

I, E. Kevin Bethel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 23, 2018

/s/ E. Kevin Bethel
E. Kevin Bethel
Director, Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

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

I, William J. Fehrman, Director, 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, 2017 (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 23, 2018

/s/ William J. Fehrman
William J. Fehrman
Director, 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, 2017 (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 23, 2018

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

EXHIBIT 32.3

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

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

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2017 (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 23, 2018

/s/ William J. Fehrman
William J. Fehrman
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.4

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

I, Nikki L. Kobliha, Director, Vice President, Chief Financial Officer and Treasurer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2017 (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 23, 2018

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Director, Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.5

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

I, Adam L. Wright, President and Chief Executive Officer of MidAmerican Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 23, 2018

/s/ Adam L. Wright
Adam L. Wright
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.6

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

I, Thomas B. Specketer, Vice President and Chief Financial Officer of MidAmerican Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 23, 2018

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.7

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

I, Adam L. Wright, President of MidAmerican Funding, LLC (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 23, 2018

/s/ Adam L. Wright
Adam L. Wright
President
(principal executive officer)

EXHIBIT 32.8

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

I, Thomas B. Specketer, Vice President and Controller of MidAmerican Funding, LLC (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 23, 2018

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 32.9

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

I, Paul J. Caudill, Chief Executive Officer of Nevada Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 23, 2018

/s/ Paul J. Caudill
Paul J. Caudill
Director and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.10

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

I, E. Kevin Bethel, Chief Financial Officer of Nevada Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 23, 2018

/s/ E. Kevin Bethel
E. Kevin Bethel
Director, Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.11

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

I, Paul J. Caudill, Chief Executive Officer of Sierra Pacific Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 23, 2018

/s/ Paul J. Caudill
Paul J. Caudill
Director and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.12

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

I, E. Kevin Bethel, Chief Financial Officer of Sierra Pacific Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company for the annual period ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 23, 2018

/s/ E. Kevin Bethel
E. Kevin Bethel
Director, Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 95

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

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2017 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. 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, 2017. 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, 2017.

	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)	Total Number of Mining Related Fatalities	Pending as of Last Day of Period(6)	Instituted During Period	Resolved During Period
Bridger (surface)	—	—	—	—	—	$ 3	—	—	1	6
Bridger (underground)	20	—	—	—	1	79	1	2	9	11
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 abated and subsequently terminated by MSHA.

(6) Amounts include two contests of proposed penalties under Subpart C 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.