Pacific Power |
Rocky Mountain Power
825 NE Multnomah, Suite 1900
Portland, Oregon 97232

March 25, 2020

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Form 10-K

Dear Commissioner:

Enclosed is a copy of PacifiCorp's most recent annual report on Form 10-K for the period ended December 31, 2019 as filed with the United States Securities and Exchange Commission pursuant to the requirement of the Securities Exchange Act of 1934.

Sincerely,

Christian Rad

Christian Rad
External Reporting Manager

Enclosure

cc: Chris Parker – Utah Division of Public Utilities
Artie Powell – Utah Division of Public Utilities
Cheryl Murray – Utah Office of Consumer Services
Michele Beck – Utah Office of Consumer Services

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, 2019

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 every Interactive Data File required to be submitted 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 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, 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 January 31, 2020, 76,549,232 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly owned by Berkshire Hathaway Energy Company. As of January 31, 2020, 357,060,915 shares of common stock, no par value, were outstanding.

All of the member's equity of MidAmerican Funding, LLC is held by its parent company, Berkshire Hathaway Energy Company, as of January 31, 2020.

All shares of outstanding common stock of MidAmerican Energy Company are owned by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of January 31, 2020, 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 January 31, 2020, 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 January 31, 2020, 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.

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

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	Berkshire Hathaway Inc.
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
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
BHE Canada	BHE Canada Holdings Corporation
AltaLink	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC
HomeServices	HomeServices of America, Inc. and its subsidiaries
BHE Pipeline Group or Pipeline Companies	Northern Natural Gas and Kern River
BHE Transmission	AltaLink and BHE U.S. Transmission
BHE Renewables	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
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

2017 Tax Reform	The Tax Cuts and Jobs Act enacted on December 22, 2017, effective January 1, 2018
AESO	Alberta Electric System Operator
AFUDC	Allowance for Funds Used During Construction
AUC	Alberta Utilities Commission
Bcf	Billion cubic feet
BTER	Base Tariff Energy Rate
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	Decatherm
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
GAAP	Accounting principles generally accepted in the United States of America
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gases
GWh	Gigawatt Hour
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	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission

OATT	Open Access Transmission Tariff
OCA	Iowa Office of Consumer Advocate
Ofgem	Office of Gas and Electric Markets
OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
PTAM	Post Test-year Adjustment Mechanism
PTC	Production Tax Credit
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
RAC	Renewable Adjustment Clause
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, creditworthiness and operational stability 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 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 January 31, 2020, 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 Chairman, beneficially owned 90.9%, 8.1% 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 BHE Canada 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 wind, solar, geothermal and hydroelectric projects, the 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 and end-users across geographically diverse service territories, including 18 states in the Western and Midwestern United States and in Great Britain and Canada.

- 88% of Berkshire Hathaway Energy's consolidated operating income during 2019 was generated from rate-regulated businesses.
- The Utilities serve 5.1 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 AltaLink serves approximately 85% of Alberta, Canada's population.
- As of December 31, 2019, the Company owns approximately 33,600 MWs of generation capacity in operation and under construction:
    - Approximately 29,000 MWs of generation capacity is owned by its regulated electric utility businesses;
    - Approximately 4,600 MWs of generation capacity is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts;
    - Owned generation capacity in operation and under construction consists of 36% wind and solar, 32% natural gas, 26% coal, 5% hydroelectric and geothermal and 1% nuclear and other; and,
    - Cumulative investments in wind, solar, geothermal and biomass generation facilities is approximately $29 billion.
- The Company owns approximately 33,400 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 16,300 miles of pipeline with a market area design capacity of approximately 8.5 Bcf of natural gas per day, serves customers and end-users in 14 states and transported approximately 8% of the total natural gas consumed in the United States during 2019.
- HomeServices closed over $134.6 billion of home sales in 2019, up 3.6% from 2018, and continued to grow its brokerage, mortgage and franchise businesses, with services in 49 states. HomeServices' franchise business has approximately 380 franchisees primarily in the United States and internationally.

As of December 31, 2019, the Company had approximately 23,000 employees, of which approximately 8,200 were 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. HomeServices currently has over 43,000 real estate agents who are independent contractors and not employees.

BHE was incorporated under the laws of the state of Iowa in 1999 and its principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580, its telephone number is (515) 242-4300 and its internet address is www.brkenergy.com.

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 141,400 square miles and includes diverse regional economies across six states. No single segment of the economy dominates the combined 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 23 years. 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 was incorporated under the laws of the state of Oregon in 1989 and its principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, its telephone number is (888) 221-7070 and its internet address is www.pacificorp.com. 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 GWhs and percentages of electricity sold to PacifiCorp's retail customers by jurisdiction for the years ended December 31 were as follows:

	2019		**2018**		**2017**	
Utah	24,490	45%	24,514	45%	24,134	44%
Oregon	13,089	24	12,867	23	13,200	24
Wyoming	9,393	17	9,393	17	9,330	17
Washington	4,145	7	3,949	7	4,221	8
Idaho	3,485	6	3,643	7	3,603	6
California	741	1	749	1	762	1
Total	55,343	100%	55,115	100%	55,250	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:

	2019		2018		2017	
GWhs sold:						
Residential	16,668	27%	16,227	26%	16,625	27%
Commercial	18,151	30	18,078	28	17,726	28
Industrial, irrigation and other	20,524	34	20,810	33	20,899	33
Total retail	55,343	91	55,115	87	55,250	88
Wholesale	5,480	9	8,309	13	7,218	12
Total GWhs sold	60,823	100%	63,424	100%	62,468	100%
Average number of retail customers (in thousands):						
Residential	1,682	87%	1,651	87%	1,622	87%
Commercial	214	11	212	11	208	11
Industrial, irrigation and other	37	2	37	2	37	2
Total	1,933	100%	1,900	100%	1,867	100%

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 2019, PacifiCorp's peak demand was 10,334 MWs in the summer and 8,604 MWs 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, 2019:

Generating Facility	Location	Energy Source	Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
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	745	745
Cholla No. 4[3]	Joseph City, AZ	Coal	1981	395	395
Naughton Nos. 1 and 2	Kemmerer, WY	Coal	1963-1968	357	357
Wyodak No. 1	Gillette, WY	Coal	1978	332	266
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	837	161
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
				8,982	5,631
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
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
Naughton No. 3[4]	Kemmerer, WY	Natural gas	1971	27	27
				3,023	2,793
HYDROELECTRIC:					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	26	26
				1,135	1,135
WIND:					
Marengo	Dayton, WA	Wind	2007-2008	210	210
Glenrock	Glenrock, WY	Wind	2008-2009 / 2019	139	139
Seven Mile Hill	Medicine Bow, WY	Wind	2008 / 2019	119	119
Dunlap Ranch	Medicine Bow, WY	Wind	2010	111	111
Leaning Juniper	Arlington, OR	Wind	2006 / 2019	100	100
Rolling Hills	Glenrock, WY	Wind	2009 / 2019	100	100
High Plains	McFadden, WY	Wind	2009 / 2019	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008 / 2019	94	94
Foote Creek[5]	Arlington, WY	Wind	1999	41	41
McFadden Ridge	McFadden, WY	Wind	2009 / 2019	28	28
				1,041	1,041
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				14,213	10,632
PROJECTS UNDER CONSTRUCTION:					
Various wind projects				1,190	1,190
				15,403	11,822

(1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the Internal Revenue Service ("IRS") as repowering. IRS rules provide for re-establishment of the PTCs for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement in such projects meets IRS guidelines, PTCs are re-established for ten years at rates that depend upon the date on which construction begins.

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

(3) In December 2019, PacifiCorp initiated steps towards retiring Cholla Unit 4 by December 31, 2020 consistent with the preferred portfolio in PacifiCorp's 2019 IRP that ceasing operations at Cholla Unit 4 as early as the end of 2020 provides economic benefits to customers. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

(4) PacifiCorp removed the unit from coal-fueled service on January 30, 2019, and determined in its 2019 IRP that converting Naughton Unit 3 to a natural gas-fueled generation resource provides economic benefits to customers. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

(5) In June 2019, PacifiCorp acquired the remaining joint owner's 21% interest in the Foote Creek I facility, and is in the process of repowering the facility.

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

	2019	2018	2017
Coal	53%	54%	56%
Natural gas	19	16	11
Hydroelectric[1]	4	5	7
Wind and other[1]	4	5	5
Total energy generated	80	80	79
Energy purchased - short-term contracts and other	10	10	11
Energy purchased - long-term contracts (renewable)[1]	10	10	10
	100%	100%	100%

(1) All or some of the renewable energy attributes associated with generation from these sources 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 jointly operates the Bridger surface and Bridger underground coal mines. These mines supplied 19%, 17% and 16% of PacifiCorp's total coal requirements during the years ended December 31, 2019, 2018 and 2017, 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, 2019, 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	14	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	3	(1)
Trapper	Craig, CO	Craig	Surface	4	(2)
				21	

(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 from 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 generating facilities that use combined-cycle, simple-cycle and steam turbines. 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 2059. 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 14 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 include those facilities where a significant portion of the equipment is currently being replaced to become eligible for federal renewable electricity PTCs for 10 years from the date the repowered facilities are placed in-service. PTCs for PacifiCorp's currently eligible wind-powered generating facilities began expiring in 2016 with final expiration in 2020. PacifiCorp is in the process of repowering all of its wind-powered generating facilities by the end of 2020 to requalify the facilities for federal renewable electricity PTCs for 10 years. The repowering project will extend the lives of the existing wind facilities by 10 years or more while increasing the anticipated electrical generation from the repowered wind facilities, on average, by approximately 26%. In addition to the discussion contained herein regarding repowering activities, refer to "Regulatory Matters" in Item 1 of this Form 10-K.

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.

Energy Imbalance Market

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 resource 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 2019 legislative session, which adjourned September 13, 2019.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory ("PacifiCorp-West") and one balancing authority area in the eastern portion of its service territory ("PacifiCorp-East"). 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 16,600 miles of transmission lines in ten states, 64,600 miles of distribution lines and 900 substations as of December 31, 2019.

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 and federal 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'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) the 140-mile, 500-kV transmission line between Aeolus Substation near Medicine Bow in Wyoming and Jim Bridger generating facility expected to be placed in-service in 2020, (e) 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, 2019, $2.5 billion had been spent and $1.6 billion, including AFUDC, had been placed in-service.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

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 October 2019, PacifiCorp filed its 2019 IRP with its state commissions. The IRP includes new transmission investments that will facilitate growth in new renewable energy resources, new storage resources, and expansion in new energy efficiency measures and demand-response programs. The IRP also includes accelerated coal-fueled generation facility retirements and the need for incremental flexible capacity resources beginning in 2026. Delivery of new transmission infrastructure that will facilitate approximately 4,400 MWs of new renewable energy resources, incremental to new renewable capacity that will come online by the end of 2020, and the addition of approximately 600 MWs of new storage capacity is planned through 2023. The IRP outlines PacifiCorp's plan to procure these near-term generating facilities through a Request for Proposals ("RFP") process that will determine how many of the new resources identified in the IRP will be developed as owned assets or power purchase agreements. Over the next 20 years, the IRP calls for retiring approximately 4,500 MWs of coal-fueled generating capacity while adding approximately 8,900 MWs of new renewable resources, incremental to new renewable capacity of approximately 2,000 MWs that will come online by the end of 2020, and approximately 2,800 MWs of new storage capacity. All or some of the renewable energy attributes associated with generation from these renewable resources may be used in future years to comply with RPS or other regulatory requirements, sold to third parties in the form of RECs or other environmental commodities, or excluded from energy purchased.

Requests for Proposals

PacifiCorp issues individual RFPs, each of which typically focuses on a specific category of generation resources consistent with the IRP or other customer-driven demands. The IRP and the RFPs provide for the identification and staged procurement of resources 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. In 2019, PacifiCorp completed the agreements for acquisition of follow-on wind turbine equipment for the final two projects associated with the 2017R RFP. PacifiCorp is not currently administering active resource RFPs.

Energy Efficiency Programs

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 2019, PacifiCorp spent $152 million on these DSM programs, resulting in an estimated 551,088 MWhs of first-year energy savings and an estimated 284 MWs of peak load management. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MWs 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, 2019, PacifiCorp had approximately 5,300 employees, of which approximately 3,000 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

General

MidAmerican Funding and MHC

MidAmerican Funding, a wholly owned subsidiary of BHE, is a holding company headquartered in Iowa that owns all of the outstanding common stock of MHC Inc. ("MHC"), which is a holding company owning all of the common stock of MidAmerican Energy and Midwest Capital Group, Inc. ("Midwest Capital"). MidAmerican Funding and MidAmerican Energy are indirect consolidated subsidiaries of Berkshire Hathaway. 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 is a substantial portion of MidAmerican Funding's and MHC's assets, revenue and earnings.

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

MidAmerican Energy, an indirect wholly owned subsidiary of BHE, is a United States regulated electric and natural gas utility company headquartered in Iowa that serves 0.8 million 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.

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:

	2019	2018	2017
Operating revenue:			
Regulated electric	76%	75%	75%
Regulated gas	23	25	25
Other	1	—	—
	100%	100%	100%
Operating income:			
Regulated electric	86%	85%	86%
Regulated gas	13	15	14
Other	1	—	—
	100%	100%	100%

MidAmerican Energy was incorporated under the laws of the state of Iowa in 1995 and its principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580, its telephone number is (515) 242-4300 and its internet address is www.midamericanenergy.com.

Regulated Electric Operations

Customers

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

	2019		2018		2017	
Iowa	24,073	92%	23,670	92%	22,365	91%
Illinois	1,894	7	1,944	7	1,891	8
South Dakota	234	1	237	1	236	1
	26,201	100%	25,851	100%	24,492	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:

	2019		2018		2017	
GWhs sold:						
Residential	6,575	18%	6,763	18%	6,207	18%
Commercial	3,921	11	3,897	11	3,761	11
Industrial	14,127	39	13,587	37	12,957	39
Other	1,578	4	1,604	4	1,567	5
Total retail	26,201	72	25,851	70	24,492	73
Wholesale	10,000	28	11,181	30	9,165	27
Total GWhs sold	36,201	100%	37,032	100%	33,657	100%
Average number of retail customers (in thousands):						
Residential	675	86%	670	86%	662	86%
Commercial	95	12	94	12	92	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	786	100%	780	100%	770	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 21%, 20% and 19% of total retail electric sales in 2019, 2018 and 2017, respectively. Sales to electronic data storage customers included in the ten largest customers comprised 12%, 9% and 9% of total retail electric sales in 2019, 2018 and 2017, 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, 2019, retail customer usage of electricity caused a new record hourly peak demand of 5,095 MWs on MidAmerican Energy's electric distribution system, which is 44 MWs greater than the previous record hourly peak demand of 5,051 MWs set July 12, 2018.

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, 2019:

Generating Facility	Location	Energy Source	Year Installed / Repowered(1)	Facility Net Capacity (MWs)(2)	Net Owned Capacity (MWs)(2)
WIND:					
Ida Grove	Ida Grove, IA	Wind	2016-2019	501	501
Orient	Greenfield, IA	Wind	2018-2019	501	501
Highland	Primghar, IA	Wind	2015	475	475
Rolling Hills	Massena, IA	Wind	2011	443	443
Beaver Creek	Ogden, IA	Wind	2017-2018	340	340
North English	Montezuma, IA	Wind	2018-2019	340	340
Pomeroy	Pomeroy, IA	Wind	2007-2011 / 2018-2019	286	286
Arbor Hill	Greenfield, IA	Wind	2018-2019	281	281
Lundgren	Otho, IA	Wind	2014	250	250
O'Brien	Primghar, IA	Wind	2016	250	250
Palo Alto	Palo Alto, IA	Wind	2019	248	248
Century	Blairsburg, IA	Wind	2005-2008 / 2017-2018	200	200
Eclipse	Adair, IA	Wind	2012	200	200
Intrepid	Schaller, IA	Wind	2004-2005 / 2017	176	176
Adair	Adair, IA	Wind	2008 / 2019	175	175
Prairie	Montezuma, IA	Wind	2017-2018	168	168
Carroll	Carroll, IA	Wind	2008 / 2019	150	150
Walnut	Walnut, IA	Wind	2008 / 2019	150	150
Vienna	Gladbrook, IA	Wind	2012-2013	150	150
Adams	Lennox, IA	Wind	2015	150	150
Wellsburg	Wellsburg, IA	Wind	2014	139	139
Laurel	Laurel, IA	Wind	2011	120	120
Macksburg	Macksburg, IA	Wind	2014	119	119
Morning Light	Adair, IA	Wind	2012	100	100
Victory	Westside, IA	Wind	2006 / 2017-2018	99	99
Ivester	Wellsburg, IA	Wind	2018	91	91
Charles City	Charles City, IA	Wind	2008 / 2018	75	75
				6,177	6,177
COAL:					
Louisa	Muscatine, IA	Coal	1983	749	659
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	698	552
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	817	487
Ottumwa	Ottumwa, IA	Coal	1981	720	375
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	510	367
George Neal Unit No. 4	Salix, IA	Coal	1979	643	261
				4,137	2,701
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	483	483
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	183	183
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	155	155
Sycamore	Johnston, IA	Gas or Oil	1974	144	144
River Hills	Des Moines, IA	Gas	1966-1967	118	118
Riverside Unit No. 5	Bettendorf, IA	Gas	1961	114	114
Coralville	Coralville, IA	Gas	1970	66	66
Moline	Moline, IL	Gas	1970	64	64
28 portable power modules	Various	Oil	2000	56	56
Parr	Charles City, IA	Gas	1969	33	33
				1,416	1,416
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,821	455

Generating Facility	Location	Energy Source	Year Installed / Repowered(1)	Facility Net Capacity (MWs)(2)	Net Owned Capacity (MWs)(2)
HYDROELECTRIC:					
Moline Unit Nos. 1-4	Moline, IL	Hydroelectric	1941	4	4
Total Available Generating Capacity				13,555	10,753
PROJECTS UNDER CONSTRUCTION:					
Various wind projects				626	626
				14,181	11,379

(1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the Internal Revenue Service ("IRS") as repowering. IRS rules provide for re-establishment of the PTCs for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement in such projects meets IRS guidelines, PTCs are re-established for ten years at rates that depend upon the date on which construction begins.

(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 MWs) 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:

	2019	2018	2017
Coal	33%	42%	40%
Nuclear	10	10	11
Natural gas	1	2	1
Wind and other(1)	44	36	38
Total energy generated	88	90	90
Energy purchased - short-term contracts and other	10	8	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 sources 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.

MidAmerican Energy is required to have resources available for dispatch by MISO 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 by MISO. 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 2023. 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 2020 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, which is currently licensed by the NRC for operation until December 14, 2032. 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. In reaction to concerns about the profitability of Quad Cities Station and Exelon Generation's ability to continue its operation, 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 ("ZECs") 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.

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, 2019, are authorized to earn over their regulatory lives a fixed rate of return on equity ranging from 11.0% to 12.2% on the depreciated 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 PTCs for 10 years from the date the facilities are placed in-service. PTCs are earned as energy from qualifying wind-powered generating facilities is produced and sold. PTCs for MidAmerican Energy's wind-powered generating facilities currently in-service began expiring in 2014, with final expiration in 2029. MidAmerican Energy has repowered, or plans to repower, 2,234 MWs of the 2,284 MWs of wind-powered generating facilities for which PTCs have expired or will expire by the end of 2022. MidAmerican Energy anticipates energy generation from the repowered facilities will increase between 19% and 30% depending upon the technology being repowered.

Of the 6,260 MWs (nominal ratings) of wind-powered generating facilities in-service as of December 31, 2019, 6,155 MWs were generating PTCs, including 1,221 MWs of repowered facilities. Of those facilities currently not generating PTCs, 55 MWs are scheduled to be repowered by the end of 2020. PTCs earned by MidAmerican Energy's wind-powered generating facilities placed in-service prior to 2013, except for repowered facilities, are included in MidAmerican Energy's Iowa energy adjustment clause, through which MidAmerican Energy is allowed to recover fluctuations in its electric retail energy costs. Facilities earning PTCs that currently benefit customers through the Iowa energy adjustment clause totaled 1,000 MWs (nominal ratings) as of December 31, 2019, with the eligibility of those facilities to earn PTCs expiring by the end of 2022. MidAmerican Energy earned PTCs totaling $378 million and $308 million in 2019 and 2018, respectively, of which 19% and 33%, respectively, were included in the Iowa energy adjustment clause.

Regional Transmission Organizations

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 decisions regarding additions to or reductions of its generation portfolio may be impacted by the MISO's minimum reserve margin requirement. The MISO requires each member to maintain a minimum reserve margin of its accredited generating capacity over its peak demand obligation based on the member's forecast filed with the MISO each year. The MISO's reserve requirement was 7.9% for the summer of 2019 and will increase to 8.9% for the summer of 2020. MidAmerican Energy's owned and contracted capacity accredited for the 2019-2020 MISO capacity auction was 5,471 MWs compared to a peak demand obligation of 4,730 MWs, or a reserve margin of 15.7%. Accredited capacity represents the amount of generation available to meet the requirements of MidAmerican Energy's retail customers and consists of MidAmerican Energy-owned generation, interruptible retail customer load, 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.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 4,100 miles of transmission lines in four states, 38,700 miles of distribution lines and 380 substations as of December 31, 2019. 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 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 distribution of natural gas to customers in its service territory and the related procurement, transportation and storage of natural gas for the benefit of those customers. 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 2019, 56% 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 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 MidAmerican Energy included 24,000 miles of natural gas main and service lines as of December 31, 2019.

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:

	2019	2018	2017
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 Dths of natural gas sold, total Dths of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2019	2018	2017
Residential	45%	43%	41%
Commercial(1)	22	21	20
Industrial(1)	4	5	4
Total retail	71	69	65
Wholesale(2)	29	31	35
	100%	100%	100%
Total Dths of natural gas sold (in thousands)	125,655	126,272	114,298
Total Dths of transportation service (in thousands)	112,143	102,198	92,136
Total average number of retail customers (in thousands)	766	759	751

(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 29, 2019, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,314,526 Dths. This peak-day delivery consisted of 68% traditional retail sales service and 32% transportation service. MidAmerican Energy's 2019/2020 winter heating season peak-day delivery as of February 3, 2020, was 1,197,419 Dths, reached on January 19, 2020. This preliminary peak-day delivery consisted of 61% traditional retail sales service and 39% 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 interstate pipeline storage services and MidAmerican Energy's 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 released 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 interstate pipeline natural gas storage services 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. Interstate pipeline storage services and MidAmerican Energy's LNG facilities reduce 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 2019/2020 winter heating season preliminary peak-day of January 19, 2020, supply sources used to meet deliveries to traditional retail sales service customers included 66% from purchases delivered on interstate pipelines, 32% from interstate pipeline storage services and 2% 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 certain 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.

Energy Efficiency Programs

MidAmerican Energy has provided a comprehensive set of demand- and energy-reduction programs to its Iowa electric and natural gas customers since 1990. The programs, collectively referred to as energy efficiency 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. In Iowa, legislation passed in 2018 provides that projected cumulative average annual costs for a natural gas energy efficiency plan cannot exceed 1.5% of expected Iowa natural gas retail rate revenue and, for an electric demand response plan and separately for an electric energy efficiency plan other than demand response, cannot exceed 2.0% of expected annual Iowa electric retail rate revenue. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for energy efficiency programs through state-specific energy efficiency service charges paid by all retail electric and natural gas customers. In 2019, $78 million was expensed for MidAmerican Energy's energy efficiency programs, which resulted in estimated first-year energy savings of 185,000 MWhs of electricity and 424,000 Dths of natural gas and an estimated peak load reduction of 316 MWs of electricity and 5,585 Dths per day of natural gas.

Employees

As of December 31, 2019, MidAmerican Funding and its subsidiaries, which includes MidAmerican Energy, had approximately 3,500 employees, of which approximately 1,500 were covered by union contracts. MidAmerican Energy has three separate contracts with locals of the International Brotherhood of Electrical Workers and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union.

NV ENERGY (NEVADA POWER AND SIERRA PACIFIC)

General

NV Energy, an indirect wholly owned subsidiary of BHE, 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 1.0 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 0.4 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 services. 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 2020 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 2019, 74% of NV Energy annual net income was recorded in the months of June through September.

Regulated electric utility operations is Nevada Power's only segment while regulated electric utility operations and regulated natural gas operations are the two segments of Sierra Pacific.

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

	2019	2018	2017
Operating revenue:			
Electric	87%	88%	88%
Gas	13	12	12
	100%	100%	100%
Operating income:			
Electric	88%	89%	88%
Gas	12	11	12
	100%	100%	100%

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

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

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:

	2019		2018		2017	
Nevada Power:						
GWhs sold:						
Residential	9,311	41%	9,970	43%	9,501	42%
Commercial	4,657	20	4,778	20	4,656	20
Industrial	5,344	24	5,534	24	6,201	28
Other	193	1	214	1	212	1
Total fully bundled	19,505	86	20,496	88	20,570	91
Distribution only service	2,613	12	2,521	11	1,830	8
Total retail	22,118	98	23,017	99	22,400	99
Wholesale	527	2	274	1	314	1
Total GWhs sold	22,645	100%	23,291	100%	22,714	100%
Average number of retail customers (in thousands):						
Residential	840	88%	825	88%	810	88%
Commercial	109	12	108	12	106	12
Industrial	2	—	2	—	2	—
Total	951	100%	935	100%	918	100%
Sierra Pacific:						
GWhs sold:						
Residential	2,491	22%	2,483	23%	2,492	24%
Commercial	2,973	26	2,998	27	2,954	28
Industrial	3,716	32	3,387	31	3,176	30
Other	16	—	16	—	16	—
Total fully bundled	9,196	80	8,884	81	8,638	82
Distribution only service	1,629	14	1,516	14	1,394	13
Total retail	10,825	94	10,400	95	10,032	95
Wholesale	662	6	558	5	561	5
Total GWhs sold	11,487	100%	10,958	100%	10,593	100%
Average number of retail customers (in thousands):						
Residential	304	86%	300	86%	295	86%
Commercial	48	14	47	14	47	14
Total	352	100%	347	100%	342	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, 48-50% of Nevada Power's and 36-38% of Sierra Pacific's regulated electric revenue is reported in the months of June through September.

The annual hourly peak customer demand on the Nevada Utilities' electric systems occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On July 29, 2019, customer usage of electricity caused an hourly peak demand of 5,611 MWs on Nevada Power's electric system, which is 513 MWs less than the record hourly peak demand of 6,124 MWs set July 28, 2016. On August 28, 2019, customer usage of electricity caused an hourly peak demand of 1,808 MWs on Sierra Pacific's electric system, which is 52 MWs less than the record hourly peak demand of 1,860 MWs set July 19, 2018.

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, 2019:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MWs)(1)	Net Owned Capacity (MWs)(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
RENEWABLES:					
Nellis	Las Vegas, NV	Solar	2015	15	15
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
				20	20
Total Nevada Power				4,384	4,384
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				6,017	5,756

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

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

	2019	2018	2017
Nevada Power:			
Natural gas	65%	64%	61%
Coal	5	6	7
Total energy generated	70	70	68
Energy purchased - long-term contracts (non-renewable)	11	10	15
Energy purchased - long-term contracts (renewable)[1]	17	16	15
Energy purchased - short-term contracts and other	2	4	2
	100%	100%	100%
Sierra Pacific:			
Natural gas	46%	48%	44%
Coal	11	8	5
Total energy generated	57	56	49
Energy purchased - long-term contracts (non-renewable)	27	29	38
Energy purchased - long-term contracts (renewable)[1]	13	12	11
Energy purchased - short-term contracts and other	3	3	2
	100%	100%	100%

(1) All or some of the renewable energy attributes associated with generation from these sources 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.

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 the BTERs, with PUCN approval, based on the last twelve months fuel costs and purchased power and to reset quarterly DEAA.

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 for 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 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 3,284 MWs with contract termination dates ranging from 2022 to 2067. Included in these contracts are 3,024 MWs of capacity of renewable energy, of which 1,815 MWs of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 1,184 MWs with contract termination dates ranging from 2022 to 2046. Included in these contracts are 998 MWs of capacity of renewable energy, of which 476 MWs 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 2019, natural gas supply net purchases averaged 310,683 and 167,283 Dths per day with the winter period contracts averaging 250,432 and 193,767 Dths per day and the summer period contracts averaging 353,197 and 148,595 Dths 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

Sierra Pacific relies on spot market solicitations for coal supplies and will regularly monitor the western coal market for opportunities to meet these needs. Sierra Pacific has a transportation services contract with Union Pacific Railroad Company to ship coal from various origins in central Utah, western Colorado and Wyoming that expires December 31, 2025. Sierra Pacific has no commitments to purchase coal for 2020 or beyond. The Navajo Generating Station was shut down in November 2019 and Nevada Power has no coal requirements going forward.

Energy Imbalance Market

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'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.

The Nevada Utilities 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 2019 legislative session, which adjourned September 13, 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 2,200 miles of transmission lines, 26,400 miles of distribution lines and 210 substations as of December 31, 2019. Sierra Pacific's transmission and distribution systems included approximately 2,300 miles of transmission lines, 17,900 miles of distribution lines and 200 substations as of December 31, 2019.

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 900 MWs 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. In December 2019, the PUCN approved an order to update the split starting January 1, 2020 to 75% for Nevada Power and 25% for Sierra Pacific to more accurately reflect the benefits obtained from the transmission line.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

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

- IRPs are filed by the Nevada Utilities for approval by the PUCN every three years and the Nevada Utilities may, as necessary, file amendments to their IRPs. IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. Nevada law governing the IRP process was modified in 2017 and now requires joint filings by Nevada Power and Sierra Pacific. 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 the Nevada Utilities' customers. Costs incurred to complete projects approved through the IRP process still remain subject to review for reasonableness by the PUCN.
- Energy Supply Plans ("ESP") are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP. The ESP has a one- to three-year planning horizon and 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 with PUCN approval required for executing contracts of longer than three years.
- Distributed Resource Plans ("DRP") are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP. The DRP establishes a formal process to aid in the cost-effective integration of distributed resources into the Nevada Utilities' distribution and transmission process and ultimately the NV Energy utilities' electricity grid.
- Action plans are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP and PUCN-approved ESP. The action plan establishes tactical execution activities with a one-month to twelve-month focus.

In April 2019, in compliance with Senate Bill No. 146, the Nevada Utilities filed their first DRP which was the first amendment to the 2019-2038 triennial IRP. In May 2019, the Nevada Utilities filed their second amendment to the IRP requesting approval for a change to the Demand-Side Action Plan to achieve a 1.25% annual energy savings target, additions to the generation portion of the Supply-Side Action Plan including a new agreement with Idaho Power Company for the orderly retirement of the North Valmy Station and updates to the Transmission Action Plan including several new transmission projects needed to serve growing distribution and transmission load. In June 2019, the Nevada Utilities filed their third amendment to the IRP requesting approval to proceed with system investments primarily related to transmission interconnections for renewable energy projects and approval for three power purchase agreements totaling 1,190-MWs of solar photovoltaic generation. The PUCN issued orders in August 2019 and December 2019 approving the significant elements of all three amendments.

There is the potential for continued price volatility in the Nevada Utilities' service territories, particularly during peak periods. 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.

Emissions Reduction and Capacity Replacement Plan

In compliance with Senate Bill No. 123, Nevada Power retired 255 MWs of coal-fueled generation in 2019 in addition to the 557 MWs of coal-fueled generation retired in 2017. Consistent with the Emissions Reduction and Capacity Replacement Plan ("ERCR Plan"), between 2014 and 2016, Nevada Power acquired 536 MWs of natural gas generating resources, executed long-term power purchase agreements for 200 MWs of nameplate renewable energy capacity and constructed a 15-MW solar photovoltaic facility. Nevada Power has the option to acquire 35 MWs of nameplate renewable energy capacity in the future under the ERCR Plan, subject to PUCN approval.

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 2019, Nevada Power spent $33 million on energy efficiency programs, resulting in an estimated 231,756 MWhs of electric energy savings and an estimated 195 MWs of electric peak load management. During 2019, Sierra Pacific spent $11 million on energy efficiency programs, resulting in an estimated 100,339 MWhs of electric energy savings and an estimated 23 MWs of electric peak load management.

Regulated Natural Gas Operations

Sierra Pacific is engaged in the distribution of natural gas to customers in its service territory and the related procurement, transportation and storage of natural gas for the benefit of those customers. 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 2019, 10% 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 3,460 miles of natural gas mains and service lines as of December 31, 2019.

Customer Usage and Seasonality

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

	2019	2018	2017
Residential	57%	55%	53%
Commercial[(1)]	29	28	27
Industrial[(1)]	10	11	9
Total retail	96	94	89
Wholesale[(2)]	4	6	11
	100%	100%	100%
Total Dths of natural gas sold (in thousands)	19,846	18,334	19,313
Total Dths of transportation service (in thousands)	2,217	2,250	1,977
Total average number of retail customers (in thousands)	170	167	165

(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 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.

(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 Sierra Pacific's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 47-56% of Sierra Pacific's regulated natural gas revenue is reported in the months of December through March.

On February 21, 2019, Sierra Pacific recorded its highest peak-day natural gas delivery of 140,287 Dths, which is 23,287 Dths less than the record peak-day delivery of 163,574 Dths 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, with PUCN approval, to reset quarterly the BTERs, based on the last twelve months fuel costs, and to reset quarterly DEAA.

Employees

As of December 31, 2019, Nevada Power had approximately 1,400 employees, of which approximately 700 were covered by a union contract with the International Brotherhood of Electrical Workers.

As of December 31, 2019, Sierra Pacific had approximately 1,000 employees, of which approximately 500 were covered by a union contract 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 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 2019, RWE Npower PLC and certain of its affiliates and British Gas Trading Limited represented 17% and 12%, 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, GEMA, through the 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 will continue through March 31, 2023.

GWhs 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:

	2019		2018		2017	
Northern Powergrid (Northeast) Limited:						
Residential	4,982	36%	5,125	36%	5,227	36%
Commercial(1)	1,644	12	1,782	13	2,222	15
Industrial(1)	7,097	51	7,134	50	6,963	48
Other	156	1	198	1	214	1
	13,879	100%	14,239	100%	14,626	100%
Northern Powergrid (Yorkshire) plc:						
Residential	7,311	35%	7,509	36%	7,612	36%
Commercial(1)	2,391	12	2,558	12	3,116	15
Industrial(1)	10,722	52	10,716	51	10,275	48
Other	236	1	268	1	290	1
	20,660	100%	21,051	100%	21,293	100%
Total electricity distributed	34,539		35,290		35,919	
Number of end-users (in thousands):						
Northern Powergrid (Northeast) Limited	1,612		1,603		1,602	
Northern Powergrid (Yorkshire) plc	2,314		2,301		2,301	
	3,926		3,904		3,903	

(1) The increase in industrial and decrease in commercial is largely due to the Great Britain-wide customer reclassifications which are in progress (as a result of Ofgem approved industry changes), negatively impacting commercial volumes by 100 GWhs in 2018 compared to 2017.

As of December 31, 2019, the combined electricity distribution network of the Northern Powergrid Distribution Companies included approximately 17,400 miles of overhead lines, 42,300 miles of underground cables and 770 major substations.

BHE PIPELINE GROUP

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 14,600 miles of natural gas pipelines, including 6,100 miles of mainline transmission pipelines and 8,500 miles of branch and lateral pipelines, with a Market Area design capacity of 6.3 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and 1.4 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 2,250 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 delivered over 1.4 trillion cubic feet ("Tcf") of natural gas to its customers in 2019.

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):

	2019			2018			2017		
Transportation:									
Market Area	$	544	64%	$	518	58%	$	504	73%
Field Area - deliveries to Demarc		106	12		102	11		36	5
Field Area - other deliveries		95	11		71	9		50	8
Total transportation		745	87		691	78		590	86
Storage		65	8		68	8		71	10
Total transportation and storage revenue		810	95		759	86		661	96
Gas, liquids and other sales		42	5		128	14		28	4
Total operating revenue	$	852	100%	$	887	100%	$	689	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 80 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, 2019, approximately 85% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2021 and approximately 55% beyond 2023. As of December 31, 2019, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is over seven 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 a weighted average remaining contract term of six years, 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 and two underground natural gas storage facilities in Kansas. Additionally, Northern Natural Gas has two LNG storage peaking units, one in Iowa and one in Minnesota, that support its transportation service. 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 cost-based and market-based rates. Firm storage contracts with cost-based rates, representing 57.1 Bcf, have an average remaining contract term of six years and are contracted at maximum tariff rates. The remaining firm storage contracts with market-based rates, representing 8.0 Bcf, have an average remaining contract term of eight 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 2019, Northern Natural Gas had two customers that each accounted for greater than 10% of its transportation and storage revenue and its ten largest customers accounted for 61% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements with terms through 2027 and 2034 to retain the majority of its two 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 2,395,000 Dths 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, Williston, including the Bakken formation, 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 typically with approximately 60% of transportation revenue 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'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 Dths, or 2.2 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 to 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 do not contract for service at Period Two rates, the volumes are turned back and sold at market rates for varying terms. As of December 31, 2019, initial Period One contracts total 331,921 Dths per day. Period Two contracts total 1,054,029 Dths per day and 606,112 Dths per day of total turned back volume has an average remaining contract term of more than two years. The remaining capacity is sold on a short-term basis at market rates.

As of December 31, 2019, approximately 83% of Kern River's design capacity of 2,166,575 Dths 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 nearly 84% 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 2021 and April 2033 and have a weighted-average remaining contract term of over eight 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, 2019, 73% of the firm capacity under contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah. Historically, Kern River has provided approximately 22% of California's demand for natural gas.

During 2019, Kern River had two customers, including Nevada Power Company, d/b/a NV Energy, that each accounted for greater than 10% of its revenue. The loss of these significant customers, 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 customer'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 tremendous increase in production from unconventional sources, such as shale gas, has reduced volatility and decreased natural gas prices across North America. This overall reduction in commodity prices has been beneficial as it reduces overall costs for Northern Natural Gas' customers and for their end-use businesses. The dramatic increase in production has also affected the supply patterns and flows. The impact has varied among pipelines according to the location and the number of competitors attached to these new supply sources. For example, the significant increase in production in the Permian area has dramatically increased short-term transportation and revenue for Northern Natural Gas by transporting excess production from the Permian area to Demarc. This increase is expected to subside as additional pipelines are constructed out of the Permian area to alleviate the current short-term constraints.

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 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 is reinforced each winter as customers expect, and receive, reliable deliveries of natural gas for their critical markets. Northern Natural Gas provides customers access to multiple supply basins that allow customers to obtain reliable supplies at competitive prices, not subject to the natural gas grid dynamics from pipeline competition that would limit customers to a singular supply source. Northern Natural Gas' Field Area has access to diverse Mid-Continent, Permian and Rockies supplies delivered to Market Area customers at Demarc at significantly lower prices than their alternative supply source. The benefits of Northern Natural Gas' system is particularly demonstrated during extreme winter conditions such as the polar vortex of 2013-2014 and severe cold weather that impacted Northern Natural Gas' Market Area in January 2019. During these periods of high market demand, customers have received all of their scheduled deliveries, without interruption, due to Northern Natural Gas' extensive, reticulated pipeline system.

Other than the short-term transportation associated with the Permian business, 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, Dominion Energy Questar Pipeline LLC and Dominion Energy Questar Overthrust Pipeline LLC; and storage facilities such as Spire Storage West 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.

BHE TRANSMISSION

BHE Canada

BHE Canada, an indirect wholly owned subsidiary of BHE, primarily owns AltaLink, a regulated electric transmission-only utility company headquartered in Alberta, Canada serving approximately 85% of Alberta's population. AltaLink's high voltage transmission lines and related facilities transmit electricity from generating facilities 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. AltaLink's transmission facilities, consisting of approximately 8,200 miles of transmission lines and 310 substations as of December 31, 2019, 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 69 kVs to 500 kVs. 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.

AltaLink 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 AltaLink 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 September 2019, the AESO released the 2019 Long-Term Outlook (LTO), which is the AESO's forecast of Alberta's load and generation over the next 20 years, and is used as one input to guide the AESO in planning Alberta's transmission system. The 2019 LTO includes a Reference Case Scenario, which is the AESO's main corporate forecast for long-term load growth and generation development in Alberta, and a set of alternative scenarios that are developed to understand future uncertainties. The Reference Case Scenario forecasts Alberta's electricity demand to grow at an annual rate of 0.9 percent over the next 20 years and a total of approximately 13 gigawatts of new generation capacity to be added for the same period. Other scenarios are developed based on modifying assumptions used in the Reference Case Scenario to reflect higher cogeneration development, alternative renewable policy, higher economic growth, lower economic growth, and a more diversified Alberta economy. The AESO indicates that it will continue monitoring economic, policy and industry development and if a scenario becomes more likely, the AESO may adopt it as its main forecast. The AESO is presently developing the Long-Term Plan which is expected to be released in the first quarter of 2020.

BHE U.S. Transmission

BHE U.S. Transmission, a wholly owned subsidiary of BHE, 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, 2019, had total assets of $3.1 billion. ETT's transmission system includes approximately 1,200 miles of transmission lines and 36 substations as of December 31, 2019.

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 had total assets of $143 million as of December 31, 2019.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects in the United States and one in the Philippines. The following table presents certain information concerning these independent power projects as of December 31, 2019:

Generating Facility	Location	Energy Source	Year Installed	Power Purchase Agreement Expiration	Power Purchaser[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
WIND:							
Grande Prairie	Nebraska	Wind	2016	2036	OPPD	400	400
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
Santa Rita	Texas	Wind	2018	2025-2038	KC, CODTX, MES	300	300
Walnut Ridge	Illinois	Wind	2018	2028	USGSA	212	212
Pinyon Pines I	California	Wind	2012	2,035	SCE	168	168
Pinyon Pines II	California	Wind	2012	2,035	SCE	132	132
Bishop Hill II	Illinois	Wind	2012	2,032	Ameren	81	81
Marshall	Kansas	Wind	2016	2036	MJMEC, KPP, KMEA & COIMO	72	72
						1,665	1,665
SOLAR:							
Topaz	California	Solar	2013-2014	2039	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
Alamo 6	Texas	Solar	2017	2042	CPS	110	110
Community Solar Gardens[6]	Minnesota	Solar	2016-2018	2041-2043	(5)	98	98
Pearl	Texas	Solar	2017	2042	CPS	50	50
						1,684	1,536
NATURAL GAS:							
Cordova	Illinois	Natural Gas	2001	NA	NA	512	512
Power Resources	Texas	Natural Gas	1988	NA	NA	212	212
Saranac	New York	Natural Gas	1994	NA	NA	245	196
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
						1,019	970
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	345	345
						345	345
HYDROELECTRIC:							
Casecnan Project[4]	Philippines	Hydroelectric	2001	2021	NIA	150	128
Wailuku	Hawaii	Hydroelectric	1993	2023	HELCO	10	10
						160	138
Total Available Generating Capacity						4,873	4,654

(1) Arizona Public Service ("APS"); NextEra Energy Marketing, LLC ("NEM"); City of Riverside, CA ("CORCA"); Imperial Irrigation District ("IID"); Sacramento Municipal Utility District ("SMUD"); Salt River Project ("SRP"); San Diego Gas & Electric Company ("SDG&E"); 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"); Kimberly-Clark Corporation ("KC"); City of Denton, TX ("CODTX"); MidAmerican Energy Services, LLC ("MES"); 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 MWs) under specified conditions. Net Owned Capacity indicates BHE Renewables' ownership of Facility Net Capacity.

(3) Approximately 17% of the Company's interests in the Imperial Valley Projects' Contract Capacity are currently sold to Southern California Edison Company under long-term power purchase agreements expiring in 2020 through 2026. Certain long-term power purchase agreement renewals for 252 MWs have been entered into with other parties at fixed prices that expire from 2028 to 2039, of which 202 MWs mature 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 98 distinct entities that each own an approximately 1-MW solar garden with independent but substantially similar terms and conditions.

Additionally, BHE Renewables has invested $3.5 billion in twenty-one wind projects sponsored by third parties, commonly referred to as tax equity investments.

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

	2019	2018	2017
Solar	48%	51%	52%
Wind	21	18	17
Geothermal	19	19	19
Hydro	2	5	6
Natural gas	10	7	6
Total operating revenue	100%	100%	100%

HOMESERVICES

HomeServices, a majority-owned subsidiary of BHE, is the 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 over 900 offices in 30 states and the District of Columbia with over 43,000 real estate agents under 47 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 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. In April 2018, HomeServices acquired the remaining 33.3% interest.

HomeServices' franchise network currently includes approximately 380 franchisees primarily in the United States and internationally in over 1,600 brokerage offices with nearly 53,000 real estate agents under two brand names. In exchange for certain fees, HomeServices provides the right to use the Berkshire Hathaway HomeServices 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, Ohio, Texas, Pennsylvania, 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, 2019, MES' contracts in place for the sale of electricity totaled 18,571 GWhs with an average term of 2.4 years and for the sale of natural gas totaled 25,717,425 Dths with an average term 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.

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. Under California 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, cities, counties and certain other public agencies have the right to choose to generate energy supply or elect an alternative provider of energy supply through the formation of a Community Choice Aggregator ("CCA"). To date, no CCA activity has occurred in PacifiCorp's California service territory. If a CCA is formed, PacifiCorp would continue to provide CCA customers transmission, distribution, metering and billing services and the CCA would provide generation supply. In addition, PacifiCorp would likely be able to collect costs from CCA customers for the generation-related costs that PacifiCorp incurred while they were customers of PacifiCorp. PacifiCorp would remain the electricity provider of last resort for these customers. 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, Chapter 704B of the Nevada Revised Statutes 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.

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

Rate Filings

Under Utah law, the UPSC must issue a written order within 240 days of a public utility’s application for a general rate change, absent an order, the proposed rates go into effect as filed and are not subject to refund; the UPSC may allow interim rates to take effect within 45 days of an application, subject to refund or surcharge, if an adequate prima facie showing is established in hearing that the interim rate change is justified.

The OPUC has the authority to suspend proposed new rates for a period not to exceed more than six months, with an additional three-month extension, beyond the 30-day time period when the new rates would otherwise go into effect. Absent suspension or other action from the OPUC, new rates automatically go into effect 30 days from filing by the utility. Upon suspension by the OPUC, the OPUC is authorized to allow collection of an interim rate, subject to refund, during the pendency of the OPUC’s review of the rate request.

In Wyoming, the WPSC can allow interim rates to go into effect 30 days after the initial application but may require a bond to secure a refund for the amount. The WPSC may suspend the rates for final approval for a period not to exceed 10 months.

The WUTC has the authority to suspend proposed new rates, subject to hearing, for a period not to exceed 10 months beyond the 30-day time period when the new rate would otherwise go into effect.

Under Idaho law, the IPUC can suspend a filing for an initial period not to exceed five months, and an additional extension of 60 days with a showing of good cause.

The CPUC has the authority to suspend proposed new rates, subject to hearing, for a period not to exceed 18 months. The CPUC may extend the suspension period on a case-by-case period.

Adjustment Mechanisms

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% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Wheeling revenue is also included in the mechanism.
		Balancing account to provide for 100% recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues after adjusting for a REC incentive authorized by the UPSC.
		Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
OPUC	Forecasted	PCAM under which 90% of the difference between forecasted net variable power costs and PTCs established under the annual TAM and actual net variable power costs and PTCs is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs and PTCs must fall outside of an established asymmetrical deadband, with a negative annual power cost variance deadband of $15 million, and a positive annual power cost variance deadband of $30 million and is subject to an earnings test of +/- 1% on PacifiCorp's allowed return on equity.
		Annual TAM based on forecasted net variable power costs and PTCs.
		RAC 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.
		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 REC revenues to customers.
		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. Under the earnings test, 50% of any excess earnings over PacifiCorp's authorized return on equity is returned to customers in addition to any surcharge or surcredit related to the revenue variance. The earnings test is asymmetrical and adjustments are not made when PacifiCorp earns at or below authorized returns on equity. 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 PTCs 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.
	CEMA for catastrophic events, allows for deferral and cost recovery of reasonable costs incurred as the result of catastrophic events, which are events for which a state or federal agency has declared a state of emergency.

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

MidAmerican Energy

Rate Filings

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 South Dakota Public Utilities Commission 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 6,639 MWs (nominal ratings) of wind-powered generating facilities, including 421 MWs (nominal ratings) under construction, as of December 31, 2019. These ratemaking principles established cost caps for the projects, below which such costs are deemed prudent by the IUB, 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, 2019, the generating facilities in service totaled $8.1 billion, or 44%, 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 11.5% with a weighted average remaining life of 33 years.

Ratemaking principles for several wind-powered generation projects have established mechanisms in Iowa where electric rate base may be reduced. The current revenue sharing mechanism originates from Wind XI and Wind XII ratemaking principles proceedings and reduces rate base for Iowa electric returns on equity exceeding an established benchmark. For 2018, sharing was triggered by MidAmerican Energy's actual equity return being above a threshold calculated annually in accordance with the IUB's 2016 Wind XI order. The threshold, not to exceed 11%, was the weighted average equity return of rate base with returns authorized via ratemaking principles proceedings and all other rate base. For all other rate base, the return is based on interest rates on 30-year A-rated utility bond yields plus 400 basis points, with a minimum return of 9.5%. In 2018 pursuant to this mechanism, MidAmerican Energy shared with customers 100% of the revenue in excess of the trigger. In December 2018, the IUB issued an order approving ratemaking principles related to MidAmerican Energy's Wind XII project. The ratemaking principles continued the revenue sharing mechanism for 2019 and beyond, maintaining the return on equity threshold for sharing and reducing the customer sharing percentage from 100% to 90%. A second mechanism, the retail customer benefit mechanism, reduces electric rate base for the value of higher cost retail energy displaced by covered wind-powered production and applies to the wind-powered generating facilities placed in-service in 2016 under the Wind X project and facilities to be constructed under the Wind XII project approved by the IUB in 2018.

Adjustment Mechanisms

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 PTCs associated with wind-powered generating facilities placed in-service prior to 2013, except for PTCs earned by repowered facilities. Eligibility for PTCs associated with MidAmerican Energy's earliest projects began expiring in 2014. Facilities currently earning PTCs that benefit customers through the Iowa energy adjustment clause totaled 1,000 MWs (nominal ratings) as of December 31, 2019, with the eligibility of those facilities to earn PTCs expiring by the end of 2022. Additionally, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in all jurisdictions. The transmission adjustment mechanisms recover costs billed by the MISO for regional transmission service. The Illinois adjustment mechanism additionally recovers MidAmerican Energy's entire transmission revenue requirement attributable to Illinois. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions and accomplish, with limited timing differences, a pass-through of the related costs to these customers. Recoveries through these adjustment mechanisms are reflected in operating revenue, and the related costs are reflected in cost of fuel and energy, operations and maintenance expense or income tax benefit, as applicable.

Of the wind-powered generating facilities placed in-service as of December 31, 2019, 3,933 MWs (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 will continue to reduce its revenue from Iowa energy adjustment clause recoveries by $12 million each calendar year.

MidAmerican Energy's cost of natural gas purchased for resale is collected for each jurisdiction 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 natural gas purchased for resale to its customers and, accordingly, has no direct effect on net income.

MidAmerican Energy's electric and natural gas energy efficiency program costs are collected through bill riders that are adjusted annually based on actual and expected costs in accordance with the energy efficiency plans filed with and approved by the respective state regulatory commission. As such, the energy efficiency program costs, which are reflected in operations and maintenance expense, and related recoveries, which are reflected in operating revenue, have no direct impact on net income.

MidAmerican Energy has income tax rider mechanisms in Iowa and Illinois that were established in response to 2017 Tax Reform, which enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the United States federal corporate income tax rate from 35% to 21%. South Dakota implemented changes to base rates in response to 2017 Tax Reform. As a result of 2017 Tax Reform, MidAmerican Energy re-measured its accumulated deferred income tax balances at the 21% rate and increased regulatory liabilities pursuant to the approved mechanisms. In December 2018, the IUB approved in final form a tax expense revision mechanism that reduces customer electric rates for the impact of the lower income tax rate on current operations, as calculated annually, and defers the amortization of excess accumulated deferred income taxes created by their re-measurement at the 21% income tax rate to a regulatory liability, the disposition of which will be determined in MidAmerican Energy's next rate case. In 2018, Iowa Senate File 2417 was signed into law, which, among other items, reduces the state of Iowa corporate tax rate from 12% to 9.8% effective in 2021. The impacts of Iowa Senate File 2417 will be included in the Iowa tax expense revision mechanism.

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 the BTERs, 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 BTERs is deferred into a balancing account. The DEAA rate clears amounts deferred into the balancing account. Nevada regulations allow an electric or natural gas utility that adjusts its BTERs on a quarterly basis to request PUCN approval to make quarterly changes to its DEAA rate if the request is in the public interest. 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 BTERs 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 EEPR, and (c) request that the PUCN reset base and amortization EEIR.

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 the integrated resource plan proceedings. 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.

Net Metering

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 for the next 80 MWs, 81% of the rate for the next 80 MWs and 75% of the rate for any additional private generation capacity. As of December 31, 2019, the cumulative installed and applied-for capacity of net metering systems under AB 405 in Nevada was 206 MWs.

Natural Disaster Mitigation Measures

Senate Bill 329 ("SB 329"), Natural Disaster Mitigation Measures, was signed into law on May 22, 2019. The legislation requires the Nevada Utilities to submit a natural disaster protection plan to the PUCN. The PUCN adopted natural disaster protection plan regulations on January 29, 2020, that require the Nevada Utilities to file their natural disaster protection plan for approval on or before March 1 of every third year, with the first filing due on March 1, 2020. The regulations also require annual updates to be filed on or before September 1 of the second and third years of the plan. The plan must include procedures, protocols and other certain information as it relates to the efforts of the Nevada Utilities to prevent or respond to a fire or other natural disaster. The expenditures incurred by the Nevada Utilities in developing and implementing the natural disaster protection plan are required to be held in a regulatory asset account, with the Nevada Utilities filing an application for recovery on or before March 1 of each year. The Nevada Utilities are required to submit their initial natural disaster protection plan to the PUCN on or before March 1, 2020 and file their first application seeking recovery of 2019 expenditures on March 1, 2020.

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 $1.3 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. The Utilities are precluded from selling at market-based rates in the PacifiCorp-East, PacifiCorp-West, Nevada Utilities, Idaho Power Company and NorthWestern Energy balancing authority areas. Wholesale electricity sales in those specific balancing authority areas are permitted at cost-based rates. PacifiCorp and the Nevada Utilities have been granted the 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 2019 and is under review by the FERC. 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 an order accepting it was issued in November 2018. 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 constructed and owns four Multi-Value Projects ("MVPs") located in Iowa and Illinois that added approximately 250 miles of 345-kV transmission line to MidAmerican Energy's transmission system since 2012. 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 is 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 is allocated to MidAmerican Energy. 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, 18 developments 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 a 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 14 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 United States 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 constructed an interim spent fuel storage installation ("ISFSI") at Quad Cities Station consisting of two pads to store spent nuclear fuel in dry casks in order to free space in the storage pool. The first dry cask was placed in-service in 2005. The first pad at the ISFSI is expected to be full and the second pad placed into operation during 2020. The first and second pads at the ISFSI are expected to facilitate storage of casks to support operations at Quad Cities Station through the end of its operating licenses.

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 $69 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. 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 invested capital. 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 the cost of capital decreases on declining rate base.

Both Northern Natural Gas' and Kern River's rates are subject to change in future general rate proceedings. Rates for natural gas pipelines are changed by filings under either Section 5 or Section 4 of the Natural Gas Act. Section 5 proceedings are initiated by the FERC or the pipeline's customers for a potential reduction to rates that the FERC finds are no longer just and reasonable. In a Section 5 proceeding, the FERC has the burden of demonstrating that the currently effective rates of the pipeline are no longer just and reasonable, and of establishing just and reasonable rates. Any rate decrease as a result of a Section 5 proceeding would be implemented prospectively upon the issuance of a final FERC order calculating the new just and reasonable rates. Section 4 rate proceedings are initiated by the natural gas pipeline, who must demonstrate that the new proposed rates are just and reasonable. The new rates as a result of a Section 4 proceeding are typically implemented six months after the Section 4 filing and are subject to refund upon issuance of a final order by the FERC.

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, and 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 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 Pipeline and Hazardous Materials Safety Administration issued the Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments final rule in October 2019. The primary change is the expansion of the pipeline integrity assessment requirements to cover moderate-consequence areas and reconfirming maximum allowable operating pressures. Pipeline operators must develop procedures to address assessment requirements and define and map locations by mid-2021 and complete 50% of the required integrity testing by 2028 and the remaining testing by 2034. The BHE Pipeline Group is assessing the impact of the rule. This is the first of three parts of the anticipated new rules. Additional final rules are expected in 2020.

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 authority. In January 2020, the Pipeline and Hazardous Materials Safety Administration issued a final rule regarding underground natural gas storage facilities that incorporates by reference the American Petroleum Institute's Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs", clarifies certain aspects of the mandatory nature of the standard and defines regulatory completion dates for underground storage facility risk assessments. Northern Natural Gas has three underground natural gas storage fields which fall under this regulation and does not expect the impact of complying with the final rule to be significant. 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 and distribution-connected generators 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 eight-year electricity distribution price control period runs from April 1, 2015 through March 31, 2023. The current price control was 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 was 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, although GEMA made no adjustments under this provision.

Under the current 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 remains constant in all subsequent years within the price control period (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.

AltaLink

AltaLink 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 AltaLink, 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 AltaLink'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 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.

AltaLink'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, AltaLink 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 AltaLink with a reasonable opportunity to (i) recover the net book value of assets and all prudently incurred costs; (ii) earn a fair return on equity; and (iii) 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. AltaLink'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. AltaLink 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, Walnut Ridge, Pinyon Pines, Santa Rita, Alamo 6 and Pearl independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act, while the Community Solar Gardens, 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, Walnut Ridge 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 2019 and is awaiting FERC action. 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 and Walnut Ridge 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 Central Region. The most recent triennial filing for the Central Region was made in December 2017 and an order accepting it was issued in November 2018. The Marshall and Grande Prairie independent power projects and power marketer CalEnergy, LLC file together for market power study purposes in the FERC-defined Southwest Power Pool Region. The most recent triennial filing for the Southwest Power Pool Region was made in December 2018 and an order accepting it was issued July 2019.

The entire output of Jumbo Road, Santa Rita, 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 Light Company within the Hawaii electric grid, which is not a FERC-jurisdictional market and therefore, Wailuku 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 ("NPC") and introducing a competitive electricity market, among other initiatives. Under the EPIRA, Power Sector Assets and Liabilities Management Corporation ("PSALM") is tasked, among others, to dispose of and privatize the assets of NPC. PSALM recently issued statements that public bidding of the administration and management of the contracted energy of the Casecnan Project's energy conversion and power purchase agreement to interested parties will be made in 2021. It is still not known what impact, if any, the implementation of this change in independent power producer administrator may have on the Casecnan Project's future operations.

Residential Real Estate Brokerage Company

HomeServices is regulated by the United States Consumer Financial Protection Bureau which enforces 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 regulates lending practices. RESPA regulates real estate settlement services including real estate closing practices, lender servicing and escrow account practices and business relationships among settlement service providers and third 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

Multi-State Process

In November 2019, PacifiCorp completed negotiations with the Multi-State Process Workgroup, resulting in a new cost allocation agreement, the 2020 Protocol. The agreement establishes a common allocation method to be used in Utah, Oregon, Wyoming, Idaho and California through 2023, and a separate method for Washington during the same time period that is based on a system approach for cost allocations and provides a path forward for Washington to achieve compliance with Washington's newly-enacted Clean Energy Transformation Act. The agreement establishes a process for the 2020 Protocol signatories to resolve remaining outstanding cost-allocations to be implemented in a new, permanent and long-term allocation method at the end of the four years. In December 2019, PacifiCorp submitted the 2020 Protocol to the UPSC, the OPUC, the WPSC and the IPUC for approval. WUTC approval of the agreement is being sought in the general rate case filing submitted in December 2019, and CPUC approval will be requested in a future rate case. In January 2020, the OPUC issued an order adopting the 2020 Protocol.

Retirement Plan Settlement Charge

During 2018, the PacifiCorp Retirement Plan incurred a settlement charge of $22 million as a result of excess lump sum distributions over the defined threshold for the year ended December 31, 2018. In December 2018, PacifiCorp submitted filings with the UPSC, the OPUC, the WPSC and the WUTC seeking approval to defer the settlement charge. Also in December 2018, an advice letter was filed with the CPUC requesting a memorandum account to track the costs associated with pension and postretirement settlements and curtailments. In April 2019, the WUTC approved PacifiCorp's requested deferral. In May 2019, the UPSC denied PacifiCorp's request. In October 2019, the request for a memorandum account was re-filed as an application with the CPUC. A hearing was held before the WPSC in October 2019 and in November 2019 the WPSC denied PacifiCorp's request. In January 2020, the OPUC issued an order denying PacifiCorp's request.

2017 Tax Reform

2017 Tax Reform enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the United States federal corporate income tax rate from 35% to 21%. In 2018, PacifiCorp agreed to refund or defer the impact of the tax law change with each of its state regulatory commissions. The status of the remaining 2017 Tax Reform proceedings is noted in the applicable state sections below.

Utah

In March 2018, PacifiCorp filed its annual EBA with the UPSC seeking approval to recover $3 million, or 0.1%, in deferred net power costs from customers for the period January 1, 2017 through December 31, 2017, reflecting the difference between base and actual net power costs in the 2017 deferral period. The rate change was approved by the UPSC effective May 1, 2018 on an interim basis. A hearing was held in February 2019, and final approval was issued in March 2019.

In March 2019, PacifiCorp filed its annual EBA with the UPSC seeking approval to recover $24 million, or 1.1%, in deferred net power costs from customers for the period January 1, 2018 through December 31, 2018, reflecting the difference between base and actual net power costs in the 2018 deferral period. The rate change was approved by the UPSC effective May 1, 2019 on an interim basis. Following a decision from the Utah Supreme Court in June 2019 that found the UPSC did not have authority to approve interim rates in conjunction with the EBA, the UPSC directed PacifiCorp to terminate the interim rate change pending final approval in the proceeding. The hearing on final approval was held in February 2020, and a final decision from the UPSC is pending.

The EBA was originally implemented as a pilot program that was designed to terminate at the end of 2019. In November 2019, the UPSC issued an order that determined continuing the EBA is in the public interest, making the EBA a permanent cost recovery mechanism.

In May 2019, Utah House Bill 411 went into effect. The legislation, among other things, authorizes the UPSC to approve a renewable energy program for communities seeking 100% renewable electricity. Participating cities were required to adopt a resolution with a goal to be on 100% renewable electricity by 2030 before December 31, 2019. Customers within a participating community may opt out of the program and maintain existing rates. Rates approved for the program may not result in any shift of costs or benefits to nonparticipating customers. Several communities in Utah, including Salt Lake City, have either recently set renewable goals or are actively considering them.

Oregon

In December 2018, PacifiCorp proposed to reduce customer rates to reflect the lower annual current income tax expense in Oregon resulting from 2017 Tax Reform. PacifiCorp reached an all-party settlement on the amortization of the current income tax expense benefits and the deferral of the decision regarding the ratemaking treatment of excess deferred income tax balances until no later than PacifiCorp's next general rate proceeding. The settlement, which resulted in a rate reduction of $48 million, or 3.7%, effective February 1, 2019, was approved by the OPUC in January 2019.

In December 2018, PacifiCorp filed a 2019 RAC application requesting recovery of $37 million, or a 2.8% increase in rates, associated with repowering of approximately 900 MWs of company-owned and installed wind facilities expected to be completed in 2019. In March 2019, the application was updated to request recovery of $32 million, or a 2.5% increase in rates. In August 2019, PacifiCorp filed an all-party settlement for the 2019 RAC that was approved by the OPUC in September 2019, providing for a total rate increase of $24 million, or 1.8%, subject to final cost updates. The settlement agreement provides for rates to be increased as the repowering projects are completed. Based on the in-service dates and final cost updates, the first rate increase of $9 million or 0.7% was effective October 1, 2019, for four repowered facilities, the second rate increase of $1 million, or 0.1%, was effective December 1, 2019, for one repowered facility and the third rate increase of $5 million or 0.4%, was effective January 1, 2020, for two repowered facilities. A final rate increase under the settlement agreement is expected to be effective March 1, 2020 for the final two remaining repowered facilities that are expected to be placed in service by the end of February 2020.

As part of the commission-approved RAC settlement, parties agreed that the Oregon-allocated net book value of certain undepreciated equipment replaced as a result of those repowerings captured in the 2019 RAC will be depreciated and offset with excess deferred income taxes resulting from 2017 Tax Reform. In 2019, accelerated depreciation of $120 million and offsetting amortization of excess deferred income taxes was recognized based on repowering activities completed through December 31, 2019.

In April 2019, PacifiCorp submitted its annual TAM filing in Oregon requesting a decrease of $15 million, or an average rate decrease of 1.2%, based on forecast net power costs and loads for calendar year 2020. The filing includes the customer benefits of repowering, including an increase in PTC. In September 2019, PacifiCorp filed an all-party settlement for the 2020 TAM. The settlement provides for a rate decrease of $20 million from the 2019 TAM, or an average rate decrease of 1.6%, effective January 1, 2020. In October 2019, the OPUC approved the all-party settlement.

In May 2019, PacifiCorp filed an application for deferral of incremental costs associated with implementing wildfire mitigation measures in Oregon. Operations and maintenance costs associated with the implementation measures are estimated to be $5 million in 2019.

In November 2019, PacifiCorp filed a 2020 RAC application requesting an annual increase in rates of $1 million, or 0.1%, associated with repowering the Glenrock III wind facility effective April 1, 2020 and an annual increase in rates of $3 million, or 0.3%, associated with repowering the Dunlap wind facility effective October 15, 2020. As part of its application, PacifiCorp proposed to offset the Oregon-allocated net book value of the replaced undepreciated wind equipment in this filing with revenues related to PacifiCorp's OATT deferral from 2017 through 2019. An all-party settlement was filed in January 2020 supporting the filed request, and a final decision from the OPUC is pending.

In November 2019 PacifiCorp requested authorization to establish an automatic adjustment clause and rate schedule for the costs and revenues related to the Oregon Corporate Activity Tax ("OCAT") that applies to tax years beginning on or after January 1, 2020. Concurrent with this filing, PacifiCorp also requested authorization to defer the OCAT tax expense. In January, 2020, the OPUC authorized the automatic adjustment clause, rate schedule and application for deferral. PacifiCorp is authorized to begin recovering the estimated OCAT expense effective February 1, 2020. The recovery adjustment for 2020 is 0.41%. The rate will be applied as a percentage surcharge on customers' bills.

In February 2020, PacifiCorp filed a general rate case in Oregon requesting an increase in base rates of $78 million, or 6.0%, effective January 1, 2021, a separate tariff rider to recover costs associated with the early retirement of Cholla Unit 4 for an increase of $17 million annually from January 2021 through April 2025 and an annual credit to customers of $25 million for amortization of remaining deferred income tax benefits associated with 2017 Tax Reform over a three-year period beginning January 2021. The request for the increase in base rates reflects recovery of Energy Vision 2020 investments, updated depreciation rates and rate design modernization proposals.

In February 2020, PacifiCorp submitted its annual TAM filing in Oregon requesting a decrease of $49 million, or 3.7%, effective January 1, 2021, based on forecast net power costs and loads for the calendar year 2021. The filing includes the customer benefits of repowering, including an increase in PTCs.

Wyoming

In April 2018, PacifiCorp filed a partial settlement related to the impact of 2017 Tax Reform with the WPSC that provided a rate reduction of $23 million, or 3.3%, effective July 1, 2018 through June 30, 2019, with the remaining tax savings to be deferred with offsets to other costs. In June 2018, PacifiCorp filed reports with the WPSC with the calculation of the full impact of the tax law change on revenue requirement of $28 million annually, comprised of $20 million in current tax savings and $8 million for the amortization of excess deferred income tax balances. In March 2019, the WPSC issued a written order approving the continued annual rate reduction of $23 million until base rates are reset in the next general rate proceeding and a $4 million offset to PacifiCorp's 2018 ECAM rates. The order reflected $20 million of current tax savings and was updated to reflect a projection of $7 million for amortization of excess deferred income tax balances. In April 2019, PacifiCorp filed a new application updating the amount of benefits being returned to customers. PacifiCorp continued the interim rate reduction that includes the previously approved $23 million and an additional $4 million reduction to offset the 2019 ECAM, effective June 15, 2019. A settlement agreement was filed in November 2019 in which the parties agreed to an additional rate reduction of $9 million effective December 1, 2019 through the end of calendar year 2020. The WPSC approved the settlement agreement at its hearing held in November 2019.

In April 2019, PacifiCorp submitted a compliance filing to the WPSC regarding bonus tax depreciation resulting in a $2 million rate reduction for the period June 15, 2019 through June 14, 2020.

In February 2019, PacifiCorp filed a certificate of public convenience and necessity application with the WPSC requesting to repower the existing Foote Creek I wind facility, which was approved without conditions in April 2019. In connection with the repowering of Foote Creek, PacifiCorp acquired the joint owner's 21% interest in the facility in June 2019.

In April 2019, PacifiCorp filed its annual ECAM and RRA application with the WPSC. The filing requests approval to recover from customers $7 million, or approximately 1.0%, in deferred net power costs for the period January 1, 2018 through December 31, 2018. The rate change went into effect on an interim basis June 15, 2019. In August, a joint notice of no contest was filed with the WPSC on behalf of PacifiCorp and the Wyoming Industrial Energy Consumers, the only intervenor in the proceeding. Interim rates were approved by the WPSC as final in November 2019. PacifiCorp offset this increase with other rate credits that went into effect on June 15, 2019.

In July 2019, Wyoming Senate Enrolled Act No. 74 went into effect. The legislation, among other things, requires electric utilities to make a good faith effort to sell a coal-fired generation facility in Wyoming before it can receive recovery in rates for capital costs associated with new generation facilities built, in whole or in part, to replace the retiring coal-fueled generation facility. The electric utility is obligated to purchase the electricity from the facility through a power purchase agreement at a price that is no greater than the utility's avoided cost as determined by the WPSC. Costs associated with an approved power purchase agreement are expected to be recoverable in rates from Wyoming customers. PacifiCorp is working with the WPSC and other stakeholders on rules to implement the legislation. The overall impacts of this legislation cannot be determined at this time.

Washington

In June 2019, PacifiCorp submitted its 2018 PCAM filing with the WUTC seeking approval to credit $7 million to the PCAM balancing account. No rate changes were requested.

In November 2019, PacifiCorp submitted its 2019 decoupling filing with the WUTC for the twelve months ended June 30, 2019. In January 2020, the WUTC approved PacifiCorp's 2019 decoupling filing, which resulted in a $12 million surcredit to customers effective February 1, 2020.

In December 2019, PacifiCorp submitted its 2021 Washington general rate case requesting an overall decrease to rates of approximately $4 million, or 1.1%, effective January 1, 2021. The case includes an increase in revenue requirement of $3 million, offset by a proposed ten-year annual surcredit of $7 million, including interest, to customers primarily associated with the amortization of excess deferred income taxes from 2017 Tax Reform. The case includes a request for approval of a new cost allocation methodology, updated depreciation rates, recovery of Energy Vision 2020 investments, and rate design modernization proposals.

Idaho

In May 2018, the IPUC approved a rate reduction of $6 million, or 2.2%, effective June 1, 2018 through May 31, 2019, to pass back a portion of the current tax benefits associated with 2017 Tax Reform. In March 2019, an all-party settlement resolving the treatment of the remaining tax savings was filed with the IPUC. In May 2019, the IPUC approved the all-party settlement resulting in the rate reduction for current tax savings being adjusted to $8 million per year, effective June 1, 2019, and $3 million related to amortization of excess deferred income taxes from 2017 Tax Reform being applied as an offset to the 2019 ECAM.

In March 2019, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $15 million, or 0.4%, for deferred costs in 2018. 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 Mine investment and changes in PTCs and RECs. In May 2019, the IPUC approved recovery of the $15 million, effective June 1, 2019, to be offset by the $3 million related to amortization of excess deferred income taxes stemming from the all-party settlement related to 2017 Tax Reform.

California

In April 2018, PacifiCorp filed a general rate case with the CPUC for an overall rate increase of $1 million, or 0.9%, effective January 1, 2019. A CPUC decision was issued in February 2020, resulting in an approximate $6 million, or 6%, rate decrease effective February 6, 2020.

On September 21, 2018, California's governor signed legislation to strengthen California's ability to prevent and recover from catastrophic wildfires, including California Senate Bill 901 ("SB 901"). SB 901 requires electric utilities to prepare and submit wildfire mitigation plans that describe the utilities' plans to prevent, combat and respond to wildfires affecting their service territories. PacifiCorp filed its wildfire mitigation plan with the CPUC on February 6, 2019. The wildfire mitigation plan incorporates the requirements outlined in SB 901, including situational awareness, system hardening, vegetation management and procedures for proactive de-energization in certain high risk areas during times of extreme danger.

SB 901 also authorized utilities, including PacifiCorp, to establish two memorandum accounts to track costs related to California Wildfire Mitigation. In March 2019, PacifiCorp received approval to establish a Fire Risk Mitigation Memorandum Account ("FRMMA"), effective January 1, 2019, to track a range of fire risk mitigation activities incremental to what is already included in PacifiCorp's rates. The CPUC also granted PacifiCorp the ability to track costs related to complying with the implementation of proactive safety power shut-off, or de-energization events, in the FRMMA.

In May 2019, the CPUC issued a decision approving PacifiCorp's 2019 Wildfire Mitigation Plan. In June 2019, following approval of its 2019 Wildfire Mitigation Plan, PacifiCorp filed to establish a second Wildfire Mitigation Plan Memorandum Account ("WMPMA") to track costs related to the implementation of its approved 2019 Plan. The WMPMA was approved effective June 4, 2019. Cost recovery is contingent on the CPUC's review of activities tracked in the memorandum accounts. In January 2020, the CPUC approved the resolution establishing procedural rules for the review and disposition of 2020 Wildfire Mitigation Plans. PacifiCorp submitted its 2020 Wildfire Mitigation Plan in February 2020.

SB 901 also required the CPUC to develop a financial stress test methodology to determine the maximum amount an electrical corporation's shareholders can pay for 2017 catastrophic wildfire damages without harming ratepayers or impacting the utility's ability to provide adequate and safe service. The CPUC's final decision in June 2019 regarding this test does not have an impact on PacifiCorp as its assets did not cause catastrophic wildfires in California in 2017.

In July 2019, California's governor signed California Assembly Bill ("AB 1054") into law. AB 1054 is comprehensive legislation addressing wildfire risk in the state of California. The new law authorizes a wildfire fund which would operate as an insurance fund to support the creditworthiness of electrical utilities, if certain utilities participate by making the required contributions, among other things. In August, PacifiCorp notified the CPUC that it will not participate in the wildfire fund.

AB 1054 also amends CPUC requirements for recovery of wildfire-related costs regardless of participation in the insurance fund. The CPUC must allow cost recovery of the costs and expenses of a "covered wildfire" which is defined as a fire ignited on or after July 12, 2019, if they are determined to be just and reasonable, meaning the electrical corporation's conduct related to the ignition was consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances, and based on the information available to the electrical corporation at the relevant point in time.

In December 2019, PacifiCorp filed an application notifying the CPUC of the early retirement of the Cholla Unit 4 generating facility and requesting authorization to establish a memorandum account associated with the retirement and decommissioning of Cholla Unit 4. The proposed memorandum account would track costs associated with the unrecovered plant balance, decommissioning and other closure-related costs. PacifiCorp requested an effective date of December 27, 2019 for the proposed memorandum account.

NV Energy (Nevada Power and Sierra Pacific)

Regulatory Rate Reviews

In June 2019, Sierra Pacific filed an electric regulatory rate review with the PUCN. The filing supported an annual revenue increase of $5 million but requested an annual revenue reduction of $5 million. In September 2019, Sierra Pacific filed an all-party settlement for the electric regulatory rate review. The settlement resolves all cost of capital and revenue requirement issues and provides for an annual revenue reduction of $5 million and requires Sierra Pacific to share 50% of regulatory earnings above 9.7% with its customers. The rate design portion of the regulatory rate review was not a part of the settlement and a hearing on rate design was held in November 2019. In December 2019, the PUCN issued an order approving the stipulation but made some adjustments to the methodology for the weather normalization component of historical sales in rates, which resulted in an additional annual revenue reduction of $3 million. The new rates were effective January 1, 2020. In January 2020, Sierra Pacific filed a petition for rehearing challenging the PUCN's adjustments to the weather normalization methodology. In February 2020, the PUCN issued an order granting the petition for rehearing.

In August 2019, as a part of the annual DEAA filing, the PUCN issued an order confirming the methodology of calculating the earnings sharing and directed Nevada Power, in its next regulatory rate review in June 2020, to address the return of the earnings sharing to customers.

2017 Tax Reform

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 2017 Tax Reform for 2018 and beyond. In March 2018, the PUCN issued an order approving the rate reduction proposed by the Nevada Utilities. The new rates were effective April 1, 2018. The order extended the procedural schedule to allow parties additional discovery relevant to 2017 Tax Reform and a hearing was held in July 2018. In September 2018, the PUCN issued an order directing the Nevada Utilities to record the amortization of any excess protected accumulated deferred income tax arising from the 2017 Tax Reform as a regulatory liability effective January 1, 2018. Subsequently, the Nevada Utilities filed a petition for reconsideration relating to the amortization of protected excess accumulated deferred income tax balances resulting from the 2017 Tax Reform. In November 2018, the PUCN issued an order granting reconsideration and reaffirming the September 2018 order. In December 2018, the Nevada Utilities filed a petition for judicial review. In January 2019, intervening parties filed statements of intent to participate in the petition for judicial review. The Nevada Utilities have filed opening briefs and the intervening parties have filed answering briefs. The hearing occurred in January 2020 and a ruling is expected in the first half of 2020.

In November 2019, FERC issued an order requiring public utilities with transmission formula rates under an OATT to include a mechanism in those transmission formula rates to deduct any excess accumulated deferred income taxes (“ADIT”) from, or add any deficient ADIT, to their rate base. Public utilities with transmission formula rates are also required to incorporate a mechanism to decrease or increase their income tax allowances by any amortized excess or deficient ADIT and to incorporate a new permanent worksheet into their transmission formula rates that will annually track information related to excess or deficient ADIT. Although the Nevada Utilities have a stated rate rather than a formula rate, they will need to demonstrate their compliance with these changes within their next FERC transmission rate proceeding.

EEPR and EEIR

In March 2019, the Nevada Utilities each filed an application to reset the EEIR and EEPR and to refund the EEIR revenue received in 2018, including carrying charges. In August 2019, the PUCN issued an order accepting a stipulation requiring the Nevada Utilities to refund the 2018 revenue and reset the rates as filed effective October 1, 2019. The current EEIR liability for Nevada Power and Sierra Pacific is $8 million and $2 million, respectively, as of December 31, 2019.

Price Stability Tariff (formerly the Optional Pricing Program)

In November 2018, the Nevada Utilities made filings with the PUCN to implement the Optional Pricing Program ("OPP"). The Nevada Utilities have designed the OPP to provide certain customers, namely those eligible to file an application pursuant to Chapter 704B of the Nevada Revised Statutes, with a market-based pricing option for renewable resources. The OPP provides for an energy rate that would replace the BTER and deferred energy accounting adjustment. The goal is to have an energy rate that yields an all-in effective rate that is competitive with market options available to such customers. In February 2019, the PUCN granted several intervenors the ability to participate in the proceeding. In June 2019, the Nevada Utilities withdrew their filings but currently plans to refile a modified tariff named the Price Stability Tariff in 2020 that responds to issues raised by intervenors.

Market Price Energy Program

In October 2019, the Nevada Utilities filed an application with the PUCN for approval of Market Price Energy Program ("MPE Program"). The MPE Program allows eligible customers to receive bundled electric service which reflects the market price of energy using energy resources that will not subject the customer to a potential impact fee, should the customer subsequently exercise its rights under Chapter 704B and elect an alternative energy supplier. In October 2019, the PUCN granted several intervenors the ability to participate in the proceeding. In January 2020, the Nevada Utilities filed a settlement stipulation, which was approved by the PUCN on January 29, 2020.

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 June 2019, the Nevada Legislature passed Senate Bill 547 ("SB 547") which modifies the 704B process. The modifications outlined in SB 547, among others, require a utility to establish limits in their integrated resource plan on the amount of load that can take service under Chapter 704B, requires customers taking service under Chapter 704B continue to pay for public program costs and requires the alternative energy providers to be licensed by the PUCN. In addition, SB 547 requires customers to file a 704B application with the PUCN in January allowing for alignment with the capacity amount established in the integrated resource plan.

As of December 31, 2019, there were two PUCN-approved applications for two fully bundled retail customers whose total estimated peak demand is approximately 10 MWs, as of the date their applications were filed with the PUCN. One of these customers transitioned to distribution only service effective January 1, 2020, and the other customer has extended its transition to on or before September 1, 2020. As of December 31, 2019, there were no applications pending before the PUCN for approval.

Northern Powergrid Distribution Companies

GEMA, through the Ofgem, published its RIIO-2 sector methodology decision in May 2019, continuing the process of developing the next set of price control arrangements that will be implemented for transmission and gas distribution networks in Great Britain. Ofgem explicitly stated that this decision did not apply for Northern Powergrid's next price control, ("ED2"), which will begin in April 2023. However, it also stated that some of the proposals may be capable of application to that price control and, in December 2019, published a decision on the framework for ED2 that confirmed the same overall approach will apply.

Regarding allowed return on capital, Ofgem has stated that it currently considers that a cost of equity of 4.3% (plus inflation calculated using the United Kingdom's consumer prices index including owner occupiers' housing costs) would be appropriate for energy networks, which is approximately 220 basis points lower than the current comparable cost of equity. This cost of equity assumption is based on a proposed debt capitalization assumption for the next price control of 60%, which is lower than the 65% debt capitalization assumption for the current price control.

In respect of ED1, in October 2019 GEMA published a decision to make allowance for certain additional costs totaling £12 million, plus RPI inflation from 2012-2013, that it judged to be beyond the control of the licensees, beyond the routine adjustments for such costs that occur annually. The adjustments, which reflect additional costs, for the licensees will flow into allowed revenues through the standard price control mechanisms and do not affect Northern Powergrid's overall financial position compared to when the current price control was set.

BHE Pipeline Group

Northern Natural Gas

In July 2018, FERC issued a final rule adopting procedures for determining whether natural gas pipelines were collecting unjust and unreasonable rates in light of the reduction in the federal corporate tax rate from 2017 Tax Reform. Pursuant to the final rule, in October 2018, Northern Natural Gas filed an informational filing on FERC Form No. 501-G and a Statement Demonstrating Why No Rate Adjustment is Necessary. In January 2019, FERC initiated a Section 5 investigation to determine whether the rates currently charged by Northern Natural Gas are just and reasonable. As required by the FERC Section 5 order, Northern Natural Gas filed a cost and revenue study in April 2019. In July 2019, Northern Natural Gas filed a Section 4 rate case requesting increases in its transportation and storage rates. In September 2019, FERC consolidated the Section 5 investigation and the Section 4 rate case into one procedural process set for hearing commencing June 2020. In January 2020, the FERC approved Northern Natural Gas' filing to implement its interim rates, including an increase of 77% from its current Market Area transmission reservation rate, subject to refund, effective January 1, 2020.

Kern River

In October 2018, Kern River filed an informational filing on FERC Form No. 501-G and a Statement Explaining Why No Rate Adjustment is Necessary, along with a Tax Reform Credit Rate Settlement in a companion docket. Kern River's Tax Reform Credit Rate Settlement offered an 11% rate credit against the Maximum Base Tariff Rates for firm service and any one-part rate that includes fixed costs which would result in an expected annual rate credit of $13 million. In November 2018, FERC approved Kern River's Tax Reform Credit effective November 15, 2018.

BHE Transmission

AltaLink

General Tariff Application

In August 2018, AltaLink filed its 2019-2021 GTA with the AUC, delivering on the first three years of its commitment to keep rates lower or flat at the approved 2018 revenue requirement of C$904 million for customers for the next five years. In addition, AltaLink proposes to provide a further tariff reduction over the three years by refunding previously collected accumulated depreciation surplus of an additional C$31 million. In November 2018, the AUC approved the 2019 interim refundable transmission tariff at C$74 million per month effective January 2019. In April 2019, AltaLink filed an update to its 2019-2021 GTA application primarily to reflect its 2018 actual results and the impact of the AUC’s decision on AltaLink's 2014-2015 Deferral Account Reconciliation Application. The application requests the approval of revised revenue requirements of C$879 million, C$882 million and C$885 million for 2019, 2020 and 2021, respectively. The forecast revenue requirement is based on an 8.5% return on equity and 37% deemed equity as approved by the AUC for 2019 and 2020.

In July 2019, AltaLink filed a 2019-2021 partial negotiated settlement application with the AUC. The application consisted of negotiated reductions totaling a C$38 million net decrease to the three-year total revenue requirement applied for in AltaLink's 2019-2021 GTA updated in April 2019. However, this may be partially offset by AltaLink's request for an additional C$20 million of forecast transmission line clearance capital as part of an excluded matter. The 2019-2021 negotiated settlement agreement excluded certain matters related to the new salvage study and salvage recovery approach, additional capital spending and incremental asset retirements. AltaLink's salvage proposal is estimated to save customers C$267 million between 2019 and 2023. Excluded matters were examined by the AUC in a hearing held in November 2019. If AltaLink is successful at hearing on the excluded matters and the negotiated settlement is approved, the revised revenue requirements will be C$873 million for 2019 and C$870 million for each of 2020 and 2021. In August 2019, AltaLink responded to information requests with respect to its 2019-2021 negotiated settlement application and the excluded matters as described above. In November 2019, a hearing to examine the excluded matters was completed with a briefing filed in January 2020. A decision from the AUC is expected in the second quarter of 2020.

2018 Generic Cost of Capital Proceeding

In July 2017, the AUC denied the utilities' request in the 2018 Generic Cost of Capital ("GCOC") proceeding 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. In August 2018, the AUC issued its decision on the 2018 GCOC proceeding to set the deemed capital structure and generic return on equity for 2018, 2019 and 2020. In its decision, the AUC set the return on equity at 8.5% for 2018, 2019 and 2020, and AltaLink's common equity ratio at 37% for 2018, 2019 and 2020.

2021 Generic Cost of Capital Proceeding

In December 2018, the AUC initiated the 2021 GCOC proceeding to consider returning to a formula-based approach in determining the return on equity for a given year, starting with 2021. In April 2019, after receiving comments from interested parties, the AUC expanded the scope of the proceeding to include a traditional non-formulaic GCOC inquiry as well as the consideration of returning to a formula-based approach. The AUC also issued a process timeline for the proceeding to commence in January 2020, with a hearing scheduled in April 2020.

In January 2020, AltaLink filed company and expert evidence, recommending a range of 8.75% to 10.5% return on equity, on a recommended equity ratio of 40% for 2021 and 2022. The Consumers' Coalition of Alberta, the Utilities Consumer Advocate and the City of Calgary filed intervenor evidence recommending a range of 5.0% to 6.9% return on equity, and an AltaLink common equity ratio of 35% to 37% for 2021 and 2022.

2014-2015 Deferral Account Reconciliation Application

In April 2017, AltaLink filed its application with the AUC with respect to its 2014 projects and deferral accounts and specific 2015 projects. The application included approximately C$2.0 billion in net capital additions. In December 2017, AltaLink 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, including AFUDC, of C$4,017 million. A hearing was held in September 2018 after the completion of an extensive information request process earlier in the year.

In December 2018 and January 2019, the AUC issued decisions approving C$3,833 million out of the C$4,017 million capital project additions, included in the application. Project costs of C$155 million were deferred to a future hearing. The AUC disallowed capital additions of approximately C$29 million including applicable AFUDC, pending receipt of additional supporting documentation for certain items. In February 2019, AltaLink filed its 2014-2015 Deferral Account Reconciliation Application compliance filing to reflect the findings, conclusions and directions arising from these decisions. In addition, the AUC ruled that it will put in placeholder amounts for the approved costs of the assets in the 2014-2015 Deferral Account Reconciliation Application proceeding until the AUC-initiated proceeding to consider the issue of transmission asset utilization. In August 2019, the AUC issued its decision with respect to AltaLink's 2014-2015 Deferral Account Reconciliation Application compliance filing. The AUC ruled that AltaLink has complied with all significant directives from the December 2018 and January 2019 decisions In September 2019, AltaLink filed a second compliance filing reflecting the directives from the AUC's August 2019 decision and final AUC approval was received in November 2019.

2016-2018 Deferral Account Reconciliation Application

In July 2019, AltaLink filed its 2016-2018 Deferral Account Reconciliation Application with the AUC. The application includes 116 projects with total gross capital additions, including AFUDC, of C$976 million. In December 2019, the AUC announced a series of technical meetings to address AltaLink's responses to certain information requests. The balance of the process steps and related schedule will be established following the AUC's ruling on the disputed information requests, which is expected by March 2020.

Alberta Electric System Operator Tariff Decision

In September 2019, the AUC issued its decision with respect to the 2018 AESO tariff. As part of this decision, the AUC approved AltaLink's proposal to refund contributions made by distribution facility owners relative to transmission projects built and owned by transmission facility owners. The proposal will benefit distribution customers by flowing through the lower cost of capital of the transmission facility owner rather than the higher cost of capital of the distribution facility owner. As directed by the AUC, AltaLink would pay FortisAlberta the unamortized contribution balance of approximately C$375 million and add the amount to AltaLink's rate base if the decision is upheld. The AUC directed the AESO to consult with AltaLink to provide a joint proposal to implement AltaLink's contribution proposal. In September 2019, FortisAlberta filed a review and variance application with the AUC requesting the AUC re-evaluate its findings with respect to AltaLink's customer contribution proposal relative to distribution facility owners. In October 2019, the AUC granted FortisAlberta's request to proceed to a review and variance with the record closed in November 2019, after submissions from FortisAlberta, AltaLink, and other interested parties. FortisAlberta also filed for permission to appeal the decision with the Court of Appeal, which will not be heard until after the AUC's review proceeding.

In December 2019, the AUC reopened the record of the review and variance proceeding and, in January 2020, issued specific information requests to each of FortisAlberta and AltaLink to clarify the evidence previously filed. AltaLink and FortisAlberta filed responses to the AUC information requests in January 2020. In February 2020, FortisAlberta filed a motion with the AUC requesting the appointment of a review panel to convene an oral hearing.

First Nations Asset Transfer Application

In November 2018, the AUC approved, with conditions, AltaLink's application filed in April 2017 to sell and transfer approximately C$100 million of transmission assets located on reserve lands to new limited partnerships with First Nations. The transfers are part of the agreement which allowed AltaLink to route the Southwest Project on reserve land. In June 2019, AltaLink closed the transaction with the Piikani Nation by transferring transmission assets of C$53 million to PiikaniLink, L.P. In January 2020, AltaLink closed the transaction with the Blood Tribe by transferring transmission assets of C$35 million to KainaiLink, L.P.

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 scheduled for no later than February 1, 2021. In January 2017, the PUCT approved ETT's request to suspend a base regulatory rate review filing scheduled for February 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. In June 2018, the PUCT approved ETT's application to reduce its transmission revenue by $28 million to reflect the lower federal income tax rate due to 2017 Tax Reform with the amortization of excess accumulated deferred federal income taxes expected to be addressed in the next base rate case.

ENVIRONMENTAL LAWS AND REGULATIONS

Each Registrant is subject to federal, state, local and foreign laws and regulations regarding climate change, RPS, air and water quality, emissions performance standards, 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. The Company has cumulative investments in wind, solar, geothermal and biomass generating facilities of approximately $29 billion and plans to spend an additional $6 billion on the construction of wind-powered generating facilities, repowering certain existing wind-powered generating facilities and funding of wind tax equity investments through 2021. Refer to "Liquidity and Capital Resources" of each respective Registrant in Item 7 of this Form 10-K for discussion of each Registrant's renewable generation-related capital expenditures.

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. On June 1, 2017, President Trump announced the United States would begin the process of withdrawing from the Paris Agreement. Under the terms of the Paris Agreement, withdrawal cannot occur until four years after its effective date, making the United States' withdrawal effective in November 2020.

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 United States Court of Appeals for the District of Columbia Circuit ("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. On December 6, 2018, the EPA announced revisions to new source performance standards for new and reconstructed coal-fueled units. EPA proposes to revise carbon dioxide emission limits for new coal-fueled facilities to 1,900 pounds per MWh for small units and 2,000 pounds per MWh for large units. The EPA would define the best system of emission reduction for new and modified units as the most efficient demonstrated steam cycle, combined with best operating practices. The EPA accepted comments on the proposal through March 18, 2019. Until such time as the EPA undertakes further action on the proposed reconsideration 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.

Affordable Clean Energy Rule

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 Clean Power Plan was stayed by the United States Supreme Court in February 2016 while litigation proceeded. On October 10, 2017, the EPA issued a proposal to repeal the Clean Power Plan, which was intended to achieve an overall reduction in carbon dioxide emissions from existing fossil-fueled electric generating units of 32% below 2005 levels. On June 19, 2019, the EPA repealed the Clean Power Plan and issued the Affordable Clean Energy rule, which fully replaced the Clean Power Plan. In the Affordable Clean Energy rule, the EPA determined that the best system of emissions reduction for existing coal-fueled power plants is heat rate improvements and identified a set of candidate technologies and measures that could improve heat rates. Measures taken to meet the standards of performance must be achieved at the source itself. States have until July 2022 to submit compliance plans to the EPA. The Affordable Clean Energy rule is 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.

Regional and State Activities

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

- In June 2013, Nevada Senate Bill 123 ("SB 123") was signed into law. Among other things, SB 123 and regulations thereunder required 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 MWs of coal-fueled generating capacity by December 31, 2014, another 250 MWs of coal-fueled generating capacity by December 31, 2017, and another 250 MWs 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-fueled 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. The PUCN may approve variations to Nevada Power's resource plans relative to requirements under SB 123. Refer to Nevada Power's Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information on the ERCR Plan.

- 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. In September 2018, the Washington Department of Commerce amended the emissions performance standards to provide that GHG emissions for base load electricity generating resources must not exceed 925 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

- In 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. On January 16, 2020, the Washington Supreme Court affirmed that the rule limits the applicability of emission standards to actual emitters and cannot be expanded to non-emitters. The court also found that the rule itself is severable, so that the Department of Ecology may continue to enforce the rule as it applies to emitters. The case was remanded for further proceedings. Pending further action by the lower court, the rule itself remains suspended, but 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. 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.

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.

In 1983, Iowa became the first state in the United States to adopt a RPS requiring the state utilities to own or to contract for a combined total of 105 MWs of renewable generating capacity and associated energy production. The IUB allocated the 105-MW requirement between the two utilities in Iowa based on each utility's percentage of their combined estimated Iowa retail peak demand in 1990 resulting in MidAmerican Energy being allocated a RPS requirement of 55.2 MWs. The utility must meet its RPS obligation by either owning renewable energy production facilities located in Iowa or entering into long-term contracts to purchase or wheel electricity from renewable production facilities located in the utility's service area.

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. In November 2018, Nevada voters approved a measure to increase the state's RPS to 50% by 2030; the measure must be voted on and approved a second time, in November 2020, in order to take effect.

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 RECs 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 1547-B ("SB 1547-B"), the Clean Electricity and Coal Transition Plan, was signed into law. SB 1547-B requires coal-fueled resources be 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. SB 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 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. In May 2019, the state of Washington enacted Senate Bill 5116, the Clean Energy Transformation Act. The legislation, among other things, requires Washington utilities to be carbon neutral by January 1, 2030 and institutes a planning target of 100% non-emitting generation by 2045. Electric utilities must also eliminate from rates coal-fired resources by December 31, 2025. PacifiCorp has begun discussions with regulators and other Washington investor-owned utilities regarding compliance obligations and implementation.

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 became law and increased the RPS target to 50% by December 31, 2030. The state's RPS was further expanded in September 2018, when California Senate Bill 100 ("SB 100"), the 100 Percent Clean Energy Act of 2018 was signed into law. In addition to requiring retail sellers to meet a RPS target of 60% by 2030, SB 100 enabled a longer-term planning target for 100% of total California retail sales to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045. 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.

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.

On June 4, 2018, EPA published final designations for much of the United States. Relevant to the Registrants, these designations include classifying Yuma County, Arizona; Clark County, Nevada; and the Northern Wasatch Front, Southern Wasatch Front and Duchesne and Uintah counties in Utah as nonattainment-marginal. These areas will be required to meet the 2015 standard three years from the August 3, 2018, effective date. All other areas relevant to the Registrants were designated attainment/unclassifiable with this same action.

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. On April 6, 2018, EPA issued a decision to retain the 2010 nitrogen dioxide national ambient air quality standard without revision.

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. On February 25, 2019, EPA issued a decision to retain the 2010 sulfur dioxide national ambient air quality standard without revision.

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.

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, Lake Side 2, Gadsby Steam and Gadsby Peakers 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.

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.

On December 27, 2018, the EPA issued a proposed revised supplemental cost finding for the MATS, as well as the required risk and technology review under Clean Air Act Section 112. EPA proposes to determine that it is not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under Section 112; however, EPA proposes to retain the emission standards and other requirements of the MATS rule, because EPA is not proposing to remove coal- and oil-fueled power plants from the list of sources regulated under Section 112. The public comment period on the proposal closes April 8, 2019. Until EPA takes final action on the rule, the relevant Registrants cannot fully determine the impacts of the proposed changes to the MATS rule.

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 “CSAPR Update Rule” was published in the Federal Register in October 2016 and required additional reductions in nitrogen oxides emissions beginning in May 2017. On December 6, 2018, EPA finalized a rule to close out the CSAPR, having determined that the CSAPR Update for the 2008 ozone NAAQS fully addressed Clean Air Act interstate transport obligations of 20 eastern states. EPA determined that 2023 is an appropriate future analytic year to evaluate remaining good neighbor obligations and that there will be no remaining nonattainment or maintenance receptors with respect to the 2008 ozone NAAQS in the eastern United States in that year. Accordingly, the 20 CSAPR Update-affected states would not contribute significantly to nonattainment in, or interfere with maintenance of, any other state with regard to the 2008 ozone NAAQS. Both the CSAPR Update and the CSAPR Close-Out rules were challenged in the D.C. Circuit Court. The D.C. Circuit ruled September 13, 2019, that because the EPA allowed upwind States to continue to significantly contribute to downwind air quality problems beyond statutory deadlines, the CSAPR Update Rule provided only a partial remedy that did not fully address interstate ozone transport, and remanded the CSAPR Update Rule back to the EPA. The D.C. Circuit Court issued an opinion October 1, 2019, finding that because the CSAPR Close-Out Rule relied on the same faulty reasoning as the CSAPR Update rule, the CSAPR Close-Out Rule must be vacated.

The CSAPR provisions are not anticipated to have a material impact on the Registrants. 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. 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. 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. Until such time as a rule is finalized, the relevant Registrants cannot determine whether additional action may be required.

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. Subsequently, the Utah Division of Air Quality completed an alternative BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2. 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 Court of Appeals ("Tenth Circuit") asking the court to overturn the EPA's actions. In July 2017, the EPA issued a letter indicating it would reconsider its FIP decision. 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. To support the reconsideration, PacifiCorp undertook additional air quality modeling using the Comprehensive Air Quality Model with Extensions ("CAMX") dispersion model. On January 14, 2019, the state of Utah submitted a SIP revision to the EPA, which includes the updated modeling information and additional analysis. On June 24, 2019, the Utah Air Quality Board unanimously voted to approve the Utah regional haze state implementation plan revision, which incorporates a best available retrofit technology alternative into Utah's regional haze state implementation plan. The best available retrofit technology alternative makes the shutdown of PacifiCorp's carbon plant enforceable under the state implementation plan and removes the requirement to install selective catalytic reduction technology on Hunter Units 1 and 2 and Huntington Units 1 and 2. The Utah Division of Air Quality submitted the state implementation plan revision to the EPA for approval by the end of 2019.

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, 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 Wyodak 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 Wyodak, 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 2017, the department approved an extension of the compliance date for Naughton Unit 3 to align with the requirements of the Wyoming SIP extending the requirement to cease coal firing to no later than January 30, 2019. The EPA issued final approval of the Wyoming SIP, including the Naughton Unit 3 gas conversion on March 21, 2019. PacifiCorp removed the unit from coal-fueled service on January 30, 2019, and its 2019 IRP Action Plan incorporates completion of the gas conversion, including all required regulatory notices and filings, by the end of 2020. On February 5, 2019, PacifiCorp submitted a reasonable progress reassessment permit application and reasonable progress determination for Jim Bridger Units 1 and 2, seeking a rescission of the December 2017 permit requiring the installation of selective catalytic reduction, to be replaced with permit imposing plant-wide emission limits to achieve better modeled visibility, fewer overall environmental impacts and lower costs of compliance. The proposal was issued for public comment in August 2019, and the state of Wyoming held a public hearing August 23, 2019 to consider the proposal and public input. The state of Wyoming is developing responses to public comment and is anticipated to submit the proposal to EPA in the first quarter 2020.

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. In December 2019, PacifiCorp initiated steps towards the early retirement of Unit 4 by December 31, 2020.

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, incorporated into an amended Colorado regional haze SIP in 2017 and approved by the EPA in August 2018. PacifiCorp identified a December 31, 2025, retirement date for Craig Unit 1 in its 2017 and 2019 IRPs.

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. On March 21, 2019, the Navajo Nation Council voted to end efforts to transition ownership and extend facility operations. The plant ceased operations at the end of 2019. Ownership transfer negotiations and closure preparations are ongoing and, until concluded, the relevant Registrant cannot determine whether additional action may be required.

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. In a separate action, on April 12, 2019, the Fifth Circuit Court of Appeals vacated two aspects of the final effluent limitation guidelines, concerning discharge limits for (1) legacy wastewater from ash transport or treatment systems and (2) combustion residual leachate from landfills or settling ponds. The Fifth Circuit found that EPA's own data did not support the agency's conclusion that impoundments were the best technology available for these two waste streams. EPA must now complete a new effluent limitation guideline for these discharge limits. On November 22, 2019, the EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. EPA proposes to ease selenium limits on flue gas desulfurization wastewater, ease the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allow a two-year extension to meet flue gas desulfurization wastewater requirements, and include additional subcategories to both wastewater categories. The proposal does not address the wastestreams at issue in the Fifth Circuit Court of Appeal's April 2019 decision. Comments on the proposed rule were accepted through January 21, 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 United States 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, which was finalized September 12, 2019. On January 22, 2018, the United States 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. On December 11, 2018, the EPA and the Corps of Engineers proposed a revised definition of "waters of the United States" that is intended to further clarify jurisdictional questions, eliminate case-by-case determinations and narrow Clean Water Act jurisdiction to align with Justice Scalia's 2006 opinion in *Rapanos v. United States*. On January 23, 2020, the EPA and the Army Corps of Engineers signed the final rule narrowing the federal government's permitting authority under the Clean Water Act. The new Navigable Waters Protection Rule, which will take effect 60 days after it is published in the *Federal Register*, redefines what waters qualify as navigable waters of the U.S. and are under Clean Water Act jurisdiction. Under the new rule, the Clean Water Act will be considered to cover territorial seas and traditional navigable waters; tributaries that flow into jurisdictional waters; wetlands that are directly adjacent to jurisdictional waters; and lakes, ponds and impoundments of jurisdictional waters. The agency and corps originally proposed six categories, but in the final version they collapsed ditches and impoundments into other categories. There are also 12 categories of waters that the agencies highlighted as being excluded from coverage, including groundwater, ephemeral streams and pools, prior converted cropland and waste treatment systems. Until the rule is fully litigated and finalized, the Registrants cannot predict the impact on overall compliance obligations.

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 was posted to the respective Registrant's coal combustion rule compliance data and information websites in March 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 facility 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.

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. Oral argument was held by the D.C. Circuit on November 20, 2017 over certain portions of the 2015 rule that had not been settled or otherwise remanded. On August 21, 2018, the D.C. Circuit issued its opinion in *Utility Solid Waste Activities Group v. EPA*, finding it was arbitrary and capricious for EPA to allow unlined ash ponds to continue operating until some unknown point in the future when groundwater contamination could be detected. The D.C. Circuit vacated the closure section of the CCR rule and remanded the issue of unlined ponds to EPA for reconsideration with specific instructions to consider harm to the environment, not just to human health. The D.C. Circuit also held EPA's decision to not regulate legacy ponds was arbitrary and capricious. While the D.C. Circuit's decision was pending, the EPA, on March 15, 2018, issued a proposal to address provisions of the final coal combustion residuals rule that were remanded back to the agency on June 14, 2016, by the D.C. Circuit. The proposal included provisions that establish alternative performance standards for owners and operators of coal combustion residuals units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by the EPA. The EPA finalized the first phase of the coal combustion residuals rule amendments on July 30, 2018, with an effective date of August 28, 2018 (the "Phase 1, Part 1 rule"). In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, EPA extended the deadline by which facilities must initiate closure of unlined ash ponds exceeding a groundwater protection standard and impoundments that do not meet the rule's aquifer location restrictions to October 31, 2020. Following submittal of competing motions from environmental groups and the EPA to stay or remand this deadline extension, on March 13, 2019, the D.C. Circuit granted EPA's request to remand the rule and left the October 31, 2020 deadline in place while the agency undertakes a new rulemaking establishing a new deadline for initiating closure. On August 14, 2019, the EPA released its "Phase 2" proposal, which contains targeted amendments to the coal combustion residuals rule in response to court remands and EPA settlement agreements, as well as issues raised in a rulemaking petition. The Phase 2 proposal modifies the definition of "beneficial use" by replacing a mass-based threshold with new location-based criteria for triggering the need to conduct an environmental demonstration; establishes a definition of "CCR storage pile" to address the temporary storage of coal combustion residuals on the ground, depending on whether the material is destined for disposal or beneficial use; makes certain changes to the rule's annual groundwater monitoring and corrective action reports to make it easier for the public to see and understand the data contained within the reports; modifies the requirements related to facilities' publicly available coal combustion residual rule websites to make the information more readily available; and establishes a risk-based groundwater monitoring protection standard for boron in the event the EPA decides to add boron to Appendix IV in the coal combustion residuals rule. The EPA accepted comments on the Phase 2 proposal through October 15, 2019. On December 2, 2019, the EPA proposed additional changes to the CCR rule in its Holistic Approach to Closure: Part A rule. This proposal addressed the D.C. Circuit's revocation of the provisions that allow unlined impoundments to continue receiving ash and establishes a new deadline of August 31, 2020, by which all unlined surface impoundments (including clay lined impoundments that do not otherwise meet the definition of “lined”) must initiate closure. The proposal also identifies and clarifies several opportunities to extend the closure deadlines for lack of alternative capacity or closure of the coal-fueled operating unit by a date certain. Comments on the proposal were accepted through January 31, 2020. In addition, it is anticipated that EPA will issue several more proposals over the coming months that further modify the CCR rule, including a federal permit program as directed under the WIIN Act; closure Part B, which may address liner equivalency demonstrations, the use of CCR in impoundment closure, and deadlines to complete closure by removal; and legacy impoundments. Until the proposals are finalized and fully litigated, the Registrants cannot determine whether additional action may be required.

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 June 28, 2018, the EPA's approval of the application was published in the Federal Register. Environmental groups, including Waterkeeper Alliance and the Sierra Club, filed suit in the United States District Court for the District of Columbia on September 26, 2018, alleging that the EPA unlawfully approved Oklahoma's permit program. This suit also incorporates claims first identified in a July 26, 2018 notice of intent to sue that alleged the EPA failed to perform nondiscretionary duties related to the development and publication of minimum guidelines for public participation in the approval of state permit programs for coal combustion residuals. To date, none of the states in which the Registrants operate has submitted an application to the EPA for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will submit an application to EPA for approval of its coal combustion residuals permit program prior to the end of 2021. In 2019, the state of Wyoming proposed to adopt state rules which incorporate the final federal rule by reference. It is anticipated that Wyoming will finalize its rule in late 2020 and submit an application to the EPA to implement a state permit program in early 2021.

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. Certain Registrants have been identified as potentially responsible parties in connection with certain disposal sites. The relevant Registrants have completed several cleanup actions and are participating in ongoing investigations and remedial actions. Costs associated with these actions are not expected to be material and are expected to be found prudent and included in rates.
- 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 14 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 11 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's nuclear decommissioning obligations.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of PacifiCorp's mining activities.
- The FERC evaluates hydroelectric systems to ensure environmental impacts are minimized, including the issuance of environmental impact statements for licensed projects both initially and upon relicensing. The FERC monitors the hydroelectric facilities for compliance with the license terms and conditions, which include environmental provisions. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 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, 2019, BHE had the following outstanding obligations:

- senior unsecured debt of $8.6 billion;
- junior subordinated debentures of $100 million;
- short-term borrowings of $1,590 million;
- guarantees and letters of credit in respect of subsidiary and equity method investments aggregating $277 million; and
- commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $2.4 billion.

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $32.3 billion as of December 31, 2019. 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 and its subsidiaries' debt do not limit BHE's 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, 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 or its subsidiaries' 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 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 could be material and could 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, 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 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 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. Similarly, in the event of a fire caused by a Registrant's operation of its businesses, including transmission or distribution systems, the relevant Registrant could be exposed to significant liability for personal and property damages that result. The extent of that liability would be determined by the applicable state law where any such damage occurred. In California, for example, where PacifiCorp operates, state law currently exposes utilities to "inverse condemnation" liability for damages resulting from events such as fires caused by the utility's operations regardless of fault. 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 or other damages. 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 financial results.

Each Registrant is subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability, data privacy 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, disposing or retiring 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 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 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 recently defeated Nevada Energy Choice Initiative; new environmental requirements, including the implementation of or changes to the Affordable Clean Energy rule, 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 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. 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.

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.

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 financial results through higher capital expenditures and operating costs, early closure of generating facilities or lower tax benefits 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 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 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 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 or requesting rate decreases 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 prudently incurred 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 or recover all of its costs even if it believes such costs to be prudently incurred.

Some state regulatory commissions have authorized recovery of certain costs above the level assumed in establishing base rates through adjustment mechanisms, which 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 adjustment mechanisms or through future general regulatory rate reviews. Any of these consequences could adversely affect each Registrant's 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 in the wholesale market, 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 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 independent 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 AltaLink, 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 AltaLink'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 regulations 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.

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

Each Registrant relies on technology in virtually all aspects of its business. Like those of many large businesses, certain of the Registrant's technology systems have been subject to computer viruses, malicious codes, unauthorized access, phishing efforts, denial-of-service attacks and other cyber attacks and each Registrant expects to be subject to similar attacks in the future as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by physical or cyber attack could result in service interruptions, safety failures, security events, regulatory compliance failures, an inability to protect information and assets against unauthorized users, and other operational difficulties. Attacks perpetrated against each Registrant's 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 adversely affect each Registrant's financial results. 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, develop, implement, adopt or protect rights around new technology, it may suffer a competitive disadvantage.

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, and the imposition of tariffs thereon when sourced by foreign providers, 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 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 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 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, including the western portion of PacifiCorp's service territory, 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 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 financial results. The extent of fluctuation in each Registrant's 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 Nevada Power, 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 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 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 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 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 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 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 17% and 12%, respectively, of distribution revenue in 2019. 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. For example, certain of BHE Renewables' solar and wind independent power projects sell all of their electrical production to either Pacific Gas and Electric Company or Southern California Edison Company, respectively. Any material payment or other 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, liquidity and financial results.

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. Furthermore, the timing of recognition of unrecognized gains and losses associated with the Registrants' defined benefit pension plans is subject to volatility due to events that may give rise to settlement accounting. Settlement events resulting from lump sum distributions offered by certain of the Registrants' defined benefit pension plans are influenced by the interest rates used to discount a participant's lump sum distribution. When the applicable interest rates are low, lump sum distributions in a given year tend to increase resulting in a higher likelihood of triggering settlement accounting.

Certain of the Registrant's pension and other postretirement benefit plans are in underfunded positions. Each Registrant may 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.

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 a subsidiary of 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's subsidiary 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 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 financial results could be adversely affected.

Cyclical fluctuations and competition 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;
- 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 a 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 financial results.

Potential changes in accounting standards may impact each Registrant's 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 financial results and disclosures. For example, beginning in 2018 all changes in the fair values of equity securities (whether realized or unrealized) are recognized as gains or losses in the relevant Registrant's 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 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 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 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, AltaLink'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 22 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K, Notes 3 and 4 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 operating electric generating facilities as of December 31, 2019:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MWs)	Net Owned Capacity (MWs)
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Oregon, Texas, New York, Arizona and Wyoming	10,938	10,659
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Wyoming, Iowa, Utah, Arizona, Nevada, Colorado and Montana	13,641	8,593
Wind	PacifiCorp, MidAmerican Energy and BHE Renewables	Iowa, Wyoming, Texas, Nebraska, Washington, California, Illinois, Oregon and Kansas	8,883	8,883
Solar	BHE Renewables and NV Energy	California, Texas, Arizona, Minnesota and Nevada	1,699	1,551
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	1,821	455
Geothermal	PacifiCorp and BHE Renewables	California and Utah	377	377
		Total	38,658	31,795

Additionally, as of December 31, 2019 the Company has electric generating facilities that are under construction in Iowa, Wyoming and Montana having total Facility Net Capacity and Net Owned Capacity of 1,816 MWs.

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 AltaLink in Alberta, Canada continue to have the power of eminent domain or similar rights in each of the jurisdictions in which they operate their respective facilities, but the United States and Canadian utilities do not have the power of eminent domain with respect to governmental, 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 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.

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 $175 million in 2019 and $450 million in 2018.

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 nor MidAmerican Energy declared or paid any cash distributions or dividends to its sole member or shareholder in 2019 and 2018.

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 $371 million in 2019. Nevada Power did not declare or pay dividends to NV Energy in 2018.

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 $46 million in 2019. Sierra Pacific did not declare or pay dividends to NV Energy in 2018.

Item 6. Selected Financial Data

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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, usage trends and other factors. This discussion should be read in conjunction 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):

	2019	2018	Change		2018	2017	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 773	$ 739	$ 34	5%	$ 739	$ 769	$ (30)	(4)%
MidAmerican Funding	781	669	112	17	669	574	95	17
NV Energy	365	317	48	15	317	346	(29)	(8)
Northern Powergrid	256	239	17	7	239	251	(12)	(5)
BHE Pipeline Group	422	387	35	9	387	277	110	40
BHE Transmission	229	210	19	9	210	224	(14)	(6)
BHE Renewables[1]	431	329	102	31	329	864	(535)	(62)
HomeServices	160	145	15	10	145	149	(4)	(3)
BHE and Other	(467)	(467)	—	—	(467)	(584)	117	(20)
Total net income attributable to BHE shareholders	$ 2,950	$ 2,568	$ 382	15%	$ 2,568	$ 2,870	$ (302)	(11)%

(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 $382 million for 2019 compared to 2018. Included in these results were pre-tax unrealized losses on the Company's investment in BYD Company Limited ($313 million, $227 million after-tax, in 2019 and $526 million, $383 million after-tax, in 2018) and a $134 million income tax benefit in 2018 related to the accrued repatriation tax on undistributed foreign earnings as a result of 2017 Tax Reform. Excluding the impacts of these items, adjusted net income attributable to BHE shareholders in 2019 was $3,177 million, an increase of $360 million, or 13%, compared to adjusted net income attributable to BHE shareholders in 2018 of $2,817 million.

Net income attributable to BHE shareholders decreased $302 million for 2018 compared to 2017. 2018 included a pre-tax unrealized loss of $526 million ($383 million after-tax) on the Company's investment in BYD Company Limited, partially offset by a $134 million income tax benefit related to the accrued repatriation tax on undistributed foreign earnings as a result of 2017 Tax Reform. 2017 included a $516 million income tax benefit as a result of 2017 Tax Reform, partially offset by $439 million of pre-tax charges ($263 million after-tax) 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 in 2018 was $2,817 million, an increase of $200 million, or 8%, compared to adjusted net income attributable to BHE shareholders in 2017 of $2,617 million.

In 2018, the Domestic Regulated Businesses began passing the benefits of lower income tax expense related to the 2017 Tax Reform to customers through various regulatory mechanisms, including lower retail rates, higher depreciation expense and reductions to rate base, which generally produced lower revenue, operating income and income tax expense in 2018 compared to 2017.

The increase in net income attributable to BHE shareholders for 2019 compared to 2018 was due to the following:

- PacifiCorp's net income increased $34 million primarily due to higher allowances for equity and borrowed funds used during construction of $55 million, lower pension and post retirement expense of $11 million and higher utility margin of $4 million, partially offset by higher depreciation and amortization expense of $25 million from additional plant placed in-service, lower PTCs of $21 million from expirations, higher interest expense of $17 million and higher operations and maintenance expense of $10 million, primarily due to costs associated with the early retirement of a coal-fueled generation unit totaling $24 million offset by a decrease in wildfire suppression costs of $9 million. Utility margin increased primarily due to lower coal-fueled generation costs, higher wholesale average market prices, higher retail revenue primarily due to favorable customer volumes and higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms, partially offset by lower wholesale volumes, higher purchased electricity costs, higher natural gas-fueled generation costs and lower net wheeling revenue. Retail customer volumes increased 0.4% primarily due to an increase in the average number of customers and the favorable impact of weather, partially offset by lower customer usage.
- MidAmerican Funding's net income increased $112 million primarily due to higher income tax benefit of $115 million, largely due to higher PTCs of $70 million and the favorable impacts of ratemaking, higher electric utility margin, higher allowances for equity and borrowed funds of $32 million and higher investment earnings, partially offset by higher interest expense of $55 million and higher depreciation and amortization expense of $30 million due to additional assets placed in-service offset by $46 million of lower Iowa revenue sharing accruals. Electric utility margin increased due to higher wind generation, higher recoveries through bill riders (substantially offset in cost of fuel and energy, operations and maintenance expense and income tax expense) and higher retail customer volumes. Electric retail customer volumes increased 1.4% as an increase in industrial volumes of 4.0% was largely offset by lower residential volumes from the unfavorable impact of weather and lower customer usage.
- NV Energy's net income increased $48 million primarily due to lower operations and maintenance expense, largely due to lower political activity expenses and lower earnings sharing accruals of $23 million at Nevada Power, partially offset by lower electric utility margin of $58 million and higher depreciation and amortization expense. Electric utility margin decreased due to lower retail customer volumes and lower average retail rates from a tax rate reduction rider effective April 1, 2018, partially offset by an increase in the average number of customers and higher wholesale and transmission revenue. Electric retail customer volumes decreased 1.4% primarily due to the impacts of weather, net of increased distribution only service customer volumes.
- Northern Powergrid's net income increased $17 million primarily due to lower overall pension expense of $23 million, largely resulting from lower pension settlement losses recognized in 2019 compared to 2018, and higher distribution tariff rates of $39 million, partially offset by lower distributed units of $21 million, higher distribution-related operating and depreciation expenses of $13 million and the stronger United States dollar of $10 million.
- BHE Pipeline Group's net income increased $35 million primarily due to higher transportation revenue of $45 million, lower property and other tax expense of $9 million due to a non-recurring property tax refund in 2019 and favorable margin of $9 million on system balancing activities, partially offset by higher depreciation and amortization expense, net of the impact of lower depreciation rates at Kern River, due to increased spending on capital projects.
- BHE Transmission's net income increased $19 million primarily due to favorable regulatory decisions received in 2019 and the unfavorable impacts of a regulatory rate order received in 2018 at AltaLink and higher equity earnings at Electric Transmission Texas, LLC, partially offset by the stronger United States dollar impact of $5 million.

- BHE Renewables' net income increased $102 million primarily due to higher wind earnings of $74 million and higher geothermal earnings of $53 million largely due to higher generation and margins from market opportunities and lower operations and maintenance expense, partially offset by lower hydro earnings of $20 million, primarily due to lower rainfall and a declining financial asset balance, and lower solar earnings of $5 million primarily due to lower insolation. Wind earnings were favorable primarily due to improved tax equity investment earnings of $49 million, earnings from new projects of $35 million and a favorable change in the valuation of a power purchase agreement of $11 million, partially offset by lower revenues on existing projects of $12 million primarily from lower generation and $8 million of unfavorable changes in the valuation of interest rate swap derivatives. Tax equity investment earnings were favorable due to $57 million of earnings from projects reaching commercial operation and $7 million of higher commitment fees, partially offset by $13 million of lower earnings from existing projects mainly due to derates caused by turbine blade repairs.
- HomeServices' net income increased $15 million primarily due to higher earnings at existing mortgage businesses of $33 million due to increased refinance activity and net income from acquired businesses of $9 million, partially offset by $36 million of lower earnings at existing brokerage businesses primarily from lower closed units and margins.
- BHE and Other net loss remained the same as the change in the after-tax unrealized position of the Company's investment in BYD Company Limited of $156 million was offset by a $134 million income tax benefit recognized in 2018 related to the accrued repatriation tax on undistributed foreign earnings as a result of 2017 Tax Reform, higher interest expense and lower net income of $14 million at MidAmerican Energy Services, LLC driven by unrealized mark-to-market losses on contracts.

The decrease in net income attributable to BHE shareholders for 2018 compared to 2017 was due to the following:

- PacifiCorp's net income decreased $30 million, primarily due to lower utility margin of $198 million and higher pension and post retirement expense of $13 million primarily due to a pension settlement charge, partially offset by a decrease in income tax expense of $181 million, primarily from a lower tax rate partially offset by $6 million of income in 2017 from 2017 Tax Reform, and higher allowance for funds used during construction of $22 million. Utility margin decreased due to lower average retail rates, including the impact of a lower federal tax rate due to the 2017 Tax Reform of $152 million, higher natural gas costs, lower wholesale revenue, higher purchased electricity costs and lower retail customer volumes, partially offset by higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms and lower coal costs. Retail customer volumes decreased by 0.2% due to impacts of weather, partially offset by an increase in the average number of customers.
- MidAmerican Funding's net income increased $95 million, primarily due to higher electric utility margin of $122 million, a higher income tax benefit of $60 million, primarily due to a $21 million increase in PTCs, a lower federal tax rate and a 2017 charge of $10 million from 2017 Tax Reform, after-tax charges of $17 million in 2017 related to the tender offer of a portion of MidAmerican Funding's 6.927% Senior Bonds due 2029 and higher allowance for borrowed and equity funds of $17 million, partially offset by higher depreciation and amortization of $109 million due to wind-powered generation and other plant placed in-service and increases for Iowa revenue sharing, higher operations and maintenance expense of $11 million and higher interest expense of $10 million. Electric utility margin increased due to higher recoveries through bill riders of $127 million (substantially offset in cost of fuel and energy, operations and maintenance expense and income tax expense), higher retail customer volumes of 5.6%, largely due to industrial growth and the favorable impact of weather, and higher wholesale revenue, partially offset by lower average retail rates of $126 million, predominantly from the impact of a lower federal tax rate due to 2017 Tax Reform, and higher generation and purchased power costs.
- NV Energy's net income decreased $29 million, primarily due to an increase in operations and maintenance expense of $71 million from higher political activity expenses and $38 million of earnings sharing established in 2018 as part of the Nevada Power 2017 regulatory rate review, a decrease in electric utility margin of $52 million and an increase in depreciation and amortization of $34 million as a result of various regulatory-directed amortizations established in the Nevada Power 2017 regulatory rate review. These decreases to net income were partially offset by a decrease in income tax expense of $122 million, primarily from a lower federal tax rate and a 2017 charge of $19 million from 2017 Tax Reform. Electric utility margin decreased due to lower average retail rates, including the impact of a lower federal tax rate due to 2017 Tax Reform of $71 million, partially offset by higher retail customer volumes of 3.0%, mainly due to the favorable impact of weather.

- Northern Powergrid's net income decreased $12 million due to higher distribution-related operating and depreciation expenses of $32 million from additional distribution network investment and higher pension expense of $13 million, largely resulting from pension settlement losses recognized in 2018 due to higher lump sum payments, partially offset by higher distribution revenue of $13 million, higher smart meter operating income of $9 million and the weaker United States dollar of $9 million. Distribution revenue increased due to higher tariff rates of $24 million, partially offset by unfavorable movements in regulatory provisions.

- BHE Pipeline Group's net income increased $110 million, due to higher transportation revenue of $113 million at Northern Natural Gas and Kern River from higher volumes and rates due to unique market opportunities and colder temperatures, a decrease in income tax expense of $50 million, primarily from a lower federal tax rate offset by $7 million of income in 2017 from 2017 Tax Reform, and lower depreciation and amortization of $33 million, largely due to lower depreciation rates at Kern River, partially offset by higher operations and maintenance expense of $88 million, primarily due to increased pipeline integrity projects at Northern Natural Gas.

- BHE Transmission's net income decreased $14 million from lower earnings at AltaLink of $10 million, primarily due to the impacts of a regulatory rate order in December 2018 and benefits from the release of contingent liabilities in 2017, partially offset by higher net income from the nonregulated natural gas generation business, and lower earnings at BHE U.S. Transmission of $4 million from lower equity earnings at Electric Transmission Texas, LLC due to the impacts of a regulatory rate order in March 2017.

- BHE Renewables' net income decreased $535 million primarily due to $628 million of income in 2017 from 2017 Tax Reform primarily resulting from reductions in deferred income tax liabilities, $45 million of higher operations and maintenance expense, mainly due to losses on asset disposals in the Imperial Valley and transformer remediation costs, and an unfavorable change in the valuation of a power purchase agreement of $13 million. These decreases were partially offset by $50 million of increased revenue from overall higher generation and pricing at existing projects, favorable earnings of $34 million from tax equity investments due largely to earnings from additional tax equity investments of $41 million offset by $7 million of higher equity losses from existing tax equity investments, $29 million of net income from additional wind and solar capacity placed in-service, $15 million of make-whole premiums paid in 2017 due to early debt retirements and a settlement of $7 million received in 2018 related to transformer issues in 2016.

- HomeServices' net income decreased $4 million, primarily due to lower margin and higher operating expenses at existing businesses, $31 million of income in 2017 from 2017 Tax Reform and $16 million of higher interest expense from increased borrowings primarily related to acquisitions, partially offset by net income of $58 million contributed from acquired businesses and a decrease in income tax expense of $28 million from a lower federal tax rate due to the impact of 2017 Tax Reform.

- BHE and Other net loss improved $117 million, primarily due to the 2017 after-tax charge of $246 million related to the tender offer of a portion of BHE's senior bonds, a 2017 charge of $127 million from 2017 Tax Reform, a $134 million income tax benefit in 2018 related to the accrued repatriation tax on undistributed foreign earnings as a result of 2017 Tax Reform and lower consolidated state and foreign income tax expense, partially offset by the after-tax unrealized loss on the investment in BYD Company Limited totaling $383 million and $58 million of lower tax benefits from a lower federal tax rate due to the impact of 2017 Tax Reform.

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):

	2019	2018	Change		2018	2017	Change	
Operating revenue:								
PacifiCorp	$ 5,068	$ 5,026	$ 42	1%	$ 5,026	$ 5,237	$ (211)	(4)%
MidAmerican Funding	2,927	3,053	(126)	(4)	3,053	2,846	207	7
NV Energy	3,037	3,039	(2)	—	3,039	3,015	24	1
Northern Powergrid	1,013	1,020	(7)	(1)	1,020	949	71	7
BHE Pipeline Group	1,131	1,203	(72)	(6)	1,203	993	210	21
BHE Transmission	707	710	(3)	—	710	699	11	2
BHE Renewables	932	908	24	3	908	838	70	8
HomeServices	4,473	4,214	259	6	4,214	3,443	771	22
BHE and Other	556	614	(58)	(9)	614	594	20	3
Total operating revenue	$ 19,844	$ 19,787	$ 57	—%	$ 19,787	$ 18,614	$ 1,173	6 %
Operating income:								
PacifiCorp	$ 1,072	$ 1,051	$ 21	2%	$ 1,051	$ 1,440	$ (389)	(27)%
MidAmerican Funding	549	550	(1)	—	550	544	6	1
NV Energy	655	607	48	8	607	766	(159)	(21)
Northern Powergrid	472	486	(14)	(3)	486	488	(2)	—
BHE Pipeline Group	572	525	47	9	525	473	52	11
BHE Transmission	323	313	10	3	313	322	(9)	(3)
BHE Renewables	336	325	11	3	325	316	9	3
HomeServices	222	214	8	4	214	214	—	—
BHE and Other	(51)	1	(52)	*	1	(41)	42	*
Total operating income	$ 4,150	$ 4,072	$ 78	2%	$ 4,072	$ 4,522	$ (450)	(10)%

* Not meaningful

PacifiCorp

Operating revenue increased $42 million for 2019 compared to 2018 due to higher retail revenue of $40 million and higher wholesale and other revenue of $2 million. Retail revenue increased primarily due to higher customer volumes of $31 million and higher average retail rates of $9 million. Retail customer volumes increased 0.4% primarily due to an increase in the average number of residential and commercial customers and the favorable impact of weather, partially offset by lower customer usage. Wholesale and other revenue increased primarily due to higher wholesale average market prices, largely offset by lower wholesale volumes.

Operating income increased $21 million for 2019 compared to 2018 primarily due to lower depreciation and amortization expense of $25 million and higher utility margin of $4 million, partially offset by higher operations and maintenance expense of $10 million, primarily due to costs associated with the early retirement of a coal-fueled generation unit totaling $24 million offset by a decrease in wildfire suppression costs of $9 million. The decrease in depreciation and amortization expense reflects prior year accelerated depreciation of Utah's share of certain thermal plant units of $174 million (offset in income tax expense) as ordered by the Utah Public Utilities Commission, partially offset by current year accelerated depreciation of Oregon's share of certain retired wind equipment due to repowering projects that were placed into service in 2019 of $120 million (offset in income tax expense) as ordered by the Oregon Public Utilities Commission and additional plant placed in-service. Utility margin increased primarily due to lower coal-fueled generation costs, higher wholesale average market prices, higher retail revenue primarily due to favorable customer volumes and higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms, partially offset by lower wholesale volumes, higher purchased electricity costs, higher natural gas-fueled generation costs and lower net wheeling revenue.

Operating revenue decreased $211 million for 2018 compared to 2017 due to lower retail revenue of $197 million and lower wholesale and other revenue of $14 million. Retail revenue decreased $180 million due to lower average retail rates, including the impact of lower federal tax rate due to 2017 Tax Reform of $152 million, and lower customer volumes of $17 million. Retail customer volumes decreased by 0.2% due to impacts of weather on the residential and commercial customer volumes and lower residential usage in all states except Utah and lower industrial usage in Oregon, Washington and Utah, partially offset by an increase in the average number of residential and commercial customers across the service territory, higher residential and commercial usage in Utah, higher irrigation usage and higher industrial usage in Wyoming and Idaho.

Operating income decreased $389 million for 2018 compared to 2017 primarily due to lower utility margin of $198 million, higher depreciation and amortization expense of $183 million, primarily due to accelerated depreciation of Utah's share of certain thermal plant units of $174 million as ordered by the Utah Public Utilities Commission. Utility margin decreased due to lower average retail rates, including the impact of a lower federal tax rate due to the 2017 Tax Reform of $151 million, higher natural gas costs, lower wholesale revenue, higher purchased electricity costs and lower retail customer volumes, partially offset by higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms and lower coal costs.

MidAmerican Funding

Operating revenue decreased $126 million for 2019 compared to 2018 primarily due to lower electric and natural gas energy efficiency program revenue of $76 million (offset in operations and maintenance expense) and lower natural gas operating revenue of $66 million, partially offset by higher other operating revenue of $13 million, primarily from nonregulated utility construction services, and higher electric operating revenue of $3 million. Electric operating revenue increased due to higher retail revenue of $77 million, partially offset by lower wholesale and other revenue of $74 million. Electric retail revenue increased due to higher customer usage of $76 million and higher recoveries through bill riders (substantially offset in cost of fuel and energy, operations and maintenance expense and income tax expense), primarily the energy adjustment clause, partially offset by lower average rates of $54 million due to sales mix and $19 million from the unfavorable impact of weather. Electric retail customer volumes increased 1.4% as an increase in industrial volumes of 4.0% was largely offset by lower residential volumes from the unfavorable impact of weather and lower customer usage. Electric wholesale and other revenue decreased due to 10.6% lower sales volumes and $35 million from lower average per-unit prices. Natural gas operating revenue decreased from lower recoveries through the purchased gas adjustment clause due to a lower average per-unit cost of natural gas sold totaling $69 million (offset in cost of sales), partially offset by an increase in retail sales volumes of 2.0% from the favorable impact of weather in 2019.

Operating income decreased $1 million for 2019 compared to 2018 primarily due to higher electric utility margin, largely offset by higher operations and maintenance expense not recovered through bill riders and higher depreciation and amortization of $30 million. Electric utility margin increased due to higher wind generation, higher recoveries through bill riders and higher retail customer volumes. Operations and maintenance expense increased mainly due to higher wind-powered generation costs of $37 million, primarily due to the new and repowered wind-powered generating facilities, and higher electric and natural gas distribution costs of $12 million, partially offset by lower fossil-fueled generation maintenance costs. The increase in depreciation and amortization expense reflects $78 million related to new and repowered wind-powered generation and other additional plant placed in-service, partially offset by lower Iowa revenue sharing accruals of $46 million.

Operating revenue increased $207 million for 2018 compared to 2017 primarily due to higher electric operating revenue of $175 million and higher natural gas operating revenue of $35 million. Electric operating revenue increased due to higher retail revenue of $102 million and higher wholesale and other revenue of $73 million. Electric retail revenue increased $127 million from higher recoveries through bill riders (substantially offset in cost of fuel and energy, operations and maintenance expense and income tax expense), primarily the energy adjustment clause, $65 million from higher customer usage, including higher industrial sales volumes, and $36 million from the impact of weather in 2018, partially offset by lower average rates of $126 million, predominantly from the impact of a lower federal tax rate due to 2017 Tax Reform. Electric retail customer volumes increased 5.6%, largely due to industrial growth and the favorable impact of weather. Electric wholesale and other revenue increased due to 22.0% higher sales volumes and higher average per-unit prices of $18 million. Natural gas operating revenue increased due to 16.7% higher retail sales volumes from the impact of weather in 2018 and industrial growth, partially offset by a lower average per-unit price of $21 million (offset in cost of sales) and other usage and rate factors, including the impact of a lower federal tax rate due to 2017 Tax Reform.

Operating income increased $6 million for 2018 compared to 2017 primarily due to higher electric utility margin of $122 million and higher natural gas utility margin of $11 million, partially offset by higher depreciation and amortization of $109 million, higher operations and maintenance expense of $11 million and higher property and other taxes of $6 million. Wind-powered generation maintenance increased $23 million primarily due to the additional wind generation facilities but was offset by lower maintenance costs for transmission, distribution and fossil-fueled generation. The increase in depreciation and amortization reflects $65 million related to additional wind generation and other plant placed in-service and increases for Iowa revenue sharing of $44 million. Electric utility margin increased due to higher recoveries through bill riders, higher retail customer volumes and higher wholesale revenue, partially offset by lower average retail rates, predominately from the impact of a lower federal tax rate due to 2017 Tax Reform, and higher generation and purchased power costs. Natural gas utility margin increased due to higher retail sales volumes from colder temperatures in 2018, partially offset by lower average rates, including the impact of a lower federal tax rate due to 2017 Tax Reform.

NV Energy

Operating revenue decreased $2 million for 2019 compared to 2018 primarily due to lower electric operating revenue of $17 million, partially offset by higher natural gas operating revenue of $15 million. Electric operating revenue decreased due to lower retail revenue of $32 million, partially offset by higher wholesale and other revenue of $15 million. Electric retail revenue decreased primarily due to lower retail customer volumes of $50 million and a decrease from a tax rate reduction rider effective April 1, 2018 of $17 million, partially offset by higher fully-bundled energy rates (offset in cost of sales) of $31 million and an increase in the average number of customers of $9 million. Electric retail customer volumes decreased 1.4% primarily due to the impacts of weather, net of increased distribution only service customer volumes. Natural gas operating revenue increased due to a higher average per-unit price (offset in cost of sales) of $13 million and higher volumes from the impacts of weather.

Operating income increased $48 million for 2019 compared to 2018 due to lower operations and maintenance expense primarily due to lower political activity expenses and lower earnings sharing accruals at Nevada Power, partially offset by lower electric utility margin of $58 million and higher depreciation and amortization expense of $26 million. Electric utility margin decreased due to higher energy costs of $41 million and lower electric operating revenue of $17 million. Energy costs increased due to higher net deferred power costs of $109 million, partially offset by lower purchased power costs of $57 million and a lower average cost of fuel for generation of $11 million.

Operating revenue increased $24 million for 2018 compared to 2017 primarily due to higher electric operating revenue of $17 million and higher natural gas operating revenue of $5 million. Electric operating revenue increased due to higher electric retail revenue of $17 million primarily due to higher fully-bundled energy rates (offset in cost of fuel and energy) of $84 million, higher customer volumes of $19 million, primarily due to the impacts of weather, and customer growth of $11 million, partially offset by a decrease from the impact of a lower federal tax rate due to 2017 Tax Reform of $71 million and lower rates from the Nevada Power 2017 regulatory rate review of $30 million. Electric retail customer volumes, including distribution only service customers, increased 3.0% compared to 2017. Natural gas operating revenue increased due to a higher average per-unit price (offset in cost of sales) of $7 million, partially offset by lower volumes from the impacts of weather.

Operating income decreased $159 million for 2018 compared to 2017 due to an increase in operations and maintenance expense of $71 million, primarily due to higher political activity expenses and $38 million of earnings sharing established in 2018 as part of the Nevada Power 2017 regulatory rate review, a decrease in electric utility margin of $52 million and higher depreciation and amortization of $34 million as a result of various regulatory-directed amortizations established in the Nevada Power 2017 regulatory rate review. Electric utility margin decreased as higher energy costs of $69 million were offset by higher electric operating revenue of $17 million. Energy costs increased due to higher net deferred power costs of $57 million and higher purchased power costs of $33 million, partially offset by a lower average cost of fuel for generation of $21 million.

Northern Powergrid

Operating revenue decreased $7 million for 2019 compared to 2018 primarily due to the stronger United States dollar of $45 million and lower distributed units of $21 million, partially offset by higher distribution tariff rates of $39 million and higher smart meter revenue of $15 million due to a larger number of units installed. Operating income decreased $14 million for 2019 compared to 2018 mainly due to the stronger United States dollar of $21 million, higher distribution-related operations and maintenance expense and higher depreciation expense related to additional distribution network and smart meter investments, partially offset by the higher distribution and smart meter revenues.

Operating revenue increased $71 million for 2018 compared to 2017 due to the weaker United States dollar of $36 million, higher smart metering revenues of $27 million and higher distribution revenues of $13 million, partially offset by lower contracting revenue of $6 million. Smart metering revenue increased due to a larger number of units installed. Distribution revenue increased primarily due to higher tariff rates of $24 million, partially offset by unfavorable movements on regulatory provisions of $6 million. Operating income decreased $2 million for 2018 compared to 2017 mainly due to higher distribution-related operating and depreciation expenses of $32 million from additional distribution network investment, partially offset by the weaker United States dollar of $18 million, higher distribution revenue of $13 million and higher smart meter operating income of $9 million.

BHE Pipeline Group

Operating revenue decreased $72 million for 2019 compared to 2018 due to lower gas sales of $89 million at Northern Natural Gas related to system balancing activities (largely offset in cost of sales), partially offset by higher transportation revenue of $19 million. Transportation revenue increased from generally higher volumes and rates, partially offset by the impact of period two rates of $26 million (largely offset in depreciation and amortization expense) and $11 million from refunds related to 2017 Tax Reform at Kern River. Operating income increased $47 million for 2019 compared to 2018 primarily due to higher transportation revenue of $45 million, lower property and other tax expense of $9 million due to a non-recurring property tax refund in 2019 and favorable margins of $9 million on system balancing activities, partially offset by higher depreciation and amortization expense, net of the impact of lower depreciation rates at Kern River, due to increased spending on capital projects.

Operating revenue increased $210 million for 2018 compared to 2017 due to higher transportation revenues of $113 million at Northern Natural Gas and Kern River from higher volumes and rates due to unique market opportunities and colder temperatures and higher gas sales of $99 million related to system balancing activities at Northern Natural Gas (largely offset in cost of sales). Operating income increased $52 million for 2018 compared to 2017 primarily due to higher transportation revenues at Northern Natural Gas and Kern River and lower depreciation and amortization of $33 million, largely due to lower depreciation rates at Kern River, partially offset by higher operations and maintenance expense, primarily due to increased pipeline integrity projects at Northern Natural Gas.

BHE Transmission

Operating revenue decreased $3 million for 2019 compared to 2018 mainly due to the stronger United States dollar of $17 million, largely offset by favorable regulatory decisions received in 2019 at AltaLink. Operating income increased $10 million for 2019 compared to 2018 primarily due to favorable regulatory decision received in 2019 and the unfavorable impacts of a regulatory rate order received in 2018 at AltaLink, partially offset by the stronger United States dollar of $8 million.

Operating revenue increased $11 million for 2018 compared to 2017 due to higher operating revenue at AltaLink, primarily from higher revenue from the nonregulated natural gas generation business and additional assets placed in-service, partially offset by the release of contingent liabilities in 2017. Operating income decreased $9 million for 2018 compared to 2017 primarily due to the impacts of a regulatory rate order received by AltaLink in December 2018 and the release of contingent liabilities in 2017, partially offset by the weaker United States dollar and higher operating income from the nonregulated natural gas generation business.

BHE Renewables

Operating revenue increased $24 million for 2019 compared to 2018 primarily due to higher wind revenues of $32 million and higher natural gas and geothermal revenues of $32 million due to higher generation and pricing from market opportunities, partially offset by lower hydro revenues of $28 million due to lower rainfall and lower solar revenues of $11 million due to lower insolation. Wind revenues increased primarily due to $33 million from new projects and a favorable change in the valuation of a power purchase agreement of $11 million, partially offset by lower generation of $12 million at existing projects. Operating income increased $11 million for 2019 compared to 2018 primarily due to the higher operating revenue and lower operations and maintenance expense of $18 million at the geothermal and hydro projects, partially offset by higher expenses related to new wind-powered generation of $30 million.

Operating revenue increased $70 million for 2018 compared to 2017 due to overall higher generation and pricing of $50 million at existing projects and $33 million from additional wind and solar capacity placed in-service, partially offset by an unfavorable change in the valuation of a power purchase agreement of $13 million. Operating income increased $9 million for 2018 compared to 2017 due to the increase in operating revenue, partially offset by higher operations and maintenance expense of $45 million related to losses on asset disposals in the Imperial Valley, transformer remediation costs and higher depreciation expense of $17 million, primarily related to additional solar and wind capacity placed in-service.

HomeServices

Operating revenue increased $259 million for 2019 compared to 2018 primarily due to an increase from acquired businesses of $221 million and higher mortgage revenue at existing businesses of $103 million due to increased refinance activity, partially offset by lower brokerage revenue at existing businesses of $74 million mainly due to a 4% decrease in closed units. Operating income increased $8 million for 2019 compared to 2018 due to an increase at existing mortgage businesses of $47 million and an increase from acquired businesses of $15 million, partially offset by a decrease at existing brokerage companies of $54 million primarily from lower closed units and margins.

Operating revenue increased $771 million for 2018 compared to 2017 due to an increase from acquired businesses totaling $838 million and a 4% increase in average home sales prices for existing brokerage businesses, offset by a 5% decrease in closed brokerage units at existing brokerage businesses. Operating income was unchanged for 2018 compared to 2017 primarily due to higher earnings from acquired businesses of $65 million offset by lower earnings from existing businesses.

BHE and Other

Operating revenue decreased $58 million for 2019 compared to 2018 primarily due to lower electricity and natural gas volumes at MidAmerican Energy Services, LLC. BHE and Other had an operating loss of $51 million in 2019 compared to operating income of $1 million in 2018 primarily due to lower margin of $25 million driven by unrealized mark-to-market losses on contracts at MidAmerican Energy Services, LLC and higher other operating costs.

Operating revenue increased $20 million for 2018 compared to 2017 primarily due to higher electricity and natural gas volumes and favorable unrealized mark-to-market gains on contracts at MidAmerican Energy Services, LLC. BHE and Other had operating income of $1 million in 2018 compared to an operating loss of $41 million in 2017 primarily due to lower other operating costs and 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):

	2019	2018	Change		2018	2017	Change	
Subsidiary debt	$ 1,477	$ 1,412	$ 65	5%	$ 1,412	$ 1,399	$ 13	1 %
BHE senior debt and other	430	421	9	2	421	423	(2)	—
BHE junior subordinated debentures	5	5	—	—	5	19	(14)	(74)
Total interest expense	$ 1,912	$ 1,838	$ 74	4%	$ 1,838	$ 1,841	$ (3)	— %

Interest expense increased $74 million for 2019 compared to 2018 primarily due to debt issuances at BHE, PacifiCorp, MidAmerican Energy and BHE Pipeline Group, partially offset by scheduled maturities, principal payments and the impact of foreign currency exchange rate movements.

Interest expense decreased $3 million for 2018 compared to 2017 primarily due to repayments of BHE junior subordinated debentures of $944 million in 2017, scheduled maturities and principal payments and early redemptions of subsidiary debt, partially offset by debt issuances at BHE, MidAmerican Funding, BHE Renewables and HomeServices.

Capitalized interest

Capitalized interest increased $16 million for 2019 compared to 2018 primarily due to higher construction work-in-progress balances at PacifiCorp and MidAmerican Energy, partially offset by a lower construction work-in-progress balance at BHE Renewables.

Capitalized interest increased $16 million for 2018 compared to 2017 primarily due to higher construction work-in-progress balances at PacifiCorp, MidAmerican Energy and BHE Renewables.

Allowance for equity funds

Allowance for equity funds increased $69 million for 2019 compared to 2018 and $28 million for 2018 compared to 2017 primarily due to higher construction work-in-progress balances at PacifiCorp and MidAmerican Energy.

Interest and dividend income

Interest and dividend income increased $4 million for 2019 compared to 2018 and $2 million for 2018 compared to 2017 primarily due to higher cash balances at PacifiCorp and MidAmerican Energy, partially offset by a lower financial asset balance at the Casecnan project.

(Losses) gains on marketable securities, net

(Losses) gains on marketable securities, net was favorable $250 million for 2019 compared to 2018 and unfavorable $552 million for 2018 compared to 2017 primarily due to the change in the unrealized position on the Company's investment in BYD Company Limited of $213 million and $(526) million, respectively.

Other, net

Other, net improved $106 million for 2019 compared to 2018 primarily due to higher investment earnings and lower non-service pension expense of $20 million, largely resulting from lower settlement losses recognized in 2019 compared to 2018 at PacifiCorp and Northern Powergrid.

Other, net improved $411 million primarily due to charges of $439 million in 2017 from tender offers related to certain long-term debt completed in December 2017.

Income tax benefit

Income tax benefit increased $15 million for 2019 compared to 2018 and the effective tax rate was (25)% for 2019 and (30)% for 2018. The effective tax rate increased primarily due to higher pre-tax income and a $134 million income tax benefit recognized in 2018 related to the accrued repatriation tax on undistributed foreign earnings as a result of 2017 Tax Reform, partially offset by higher PTCs of $188 million, the favorable impacts of ratemaking and lower consolidated state income taxes in 2019.

Income tax benefit increased $29 million for 2018 compared to 2017 and the effective tax rate was (30)% for 2018 and (22)% for 2017. The effective tax rate decreased primarily due to the reduction in the United States federal corporate income tax rate from 35% to 21%, effective January 1, 2018, the favorable impacts of ratemaking of $140 million, including amortization of Utah's share of non-protected excess deferred income taxes used to accelerate depreciation of certain thermal plant units as ordered by the Utah Public Utilities Commission, a $134 million income tax benefit recognized in 2018 related to the accrued repatriation tax on undistributed foreign earnings as a result of 2017 Tax Reform, higher PTCs of $76 million and lower United States income taxes on foreign earnings of $40 million, partially offset by net impacts of $731 million in 2017 as a result of 2017 Tax Reform.

The 2017 Tax Reform most notably lowered the United States 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.

Federal renewable electricity PTCs 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 $0.025 per kilowatt hour was applied to 2019 production and a credit of $0.024 per kilowatt hour was applied to 2018 and 2017 production, which resulted in PTCs of $759 million in 2019, $571 million in 2018 and $495 million in 2017.

Equity (loss) income

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

	2019	2018	Change		2018	2017	Change	
Equity income (loss):								
ETT	$ 65	$ 62	$ 3	5%	$ 62	$ (62)	$ 124	*
Tax equity investments	(148)	(61)	(87)	*	(61)	(120)	59	(49)%
Agua Caliente	28	27	1	4	27	24	3	13
HomeServices	7	8	(1)	(13)	8	6	2	33
Other	4	7	(3)	(43)	7	1	6	*
Total equity (loss) income	$ (44)	$ 43	$ (87)	*	$ 43	$ (151)	$ 194	*

* Not meaningful

Equity income decreased $87 million for 2019 compared to 2018 primarily due higher pre-tax equity losses from tax equity investments at BHE Renewables. PTCs and other income tax benefits from these projects are recognized in income tax expense.

Equity income increased $194 million for 2018 compared to 2017 primarily due to the impacts of 2017 Tax Reform, which decreased equity income in 2017 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. Additionally, 2018 pre-tax equity earnings were lower at Electric Transmission Texas, LLC primarily due to the impacts of new retail rates effective March 2017.

Net income attributable to noncontrolling interests

Net income attributable to noncontrolling interests decreased $5 million for 2019 compared to 2018 mainly due to lower earnings at the Casecnan project.

Net income attributable to noncontrolling interests decreased $17 million for 2018 compared to 2017 mainly due to the April 2018 purchase of a redeemable noncontrolling interest at HomeServices.

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 18 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, 2019, the Company's total net liquidity was as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Canada	Other	Total
Cash and cash equivalents	$ 13	$ 30	$ 288	$ 49	$ 334	$ 69	$ 257	$ 1,040
Credit facilities	3,500	1,200	1,309	650	199	674	1,880	9,412
Less:								
Short-term debt	(1,590)	(130)	—	—	—	(211)	(1,283)	(3,214)
Tax-exempt bond support and letters of credit	—	(256)	(370)	—	—	(3)	—	(629)
Net credit facilities	1,910	814	939	650	199	460	597	5,569
Total net liquidity	$ 1,923	$ 844	$ 1,227	$ 699	$ 533	$ 529	$ 854	$ 6,609
Credit facilities:								
Maturity dates	2022	2022	2020, 2022	2022	2022	2023	2020, 2022	

Refer to Note 9 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.

On January 29, 2019, PG&E Corporation and Pacific Gas and Electric Company filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of California. As a result, the Company does not expect to receive distributions from Topaz or Agua Caliente in the near term.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2019 and 2018 were $6.2 billion and $6.8 billion, respectively. The decrease was primarily due to changes in working capital, partially offset by an increase in income tax receipts.

Net cash flows from operating activities for the years ended December 31, 2018 and 2017 were $6.8 billion and $6.1 billion, respectively. The increase was primarily due to changes in working capital and an increase in income tax receipts.

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.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2019 and 2018 were $(9.0) billion and $(7.0) billion, respectively. The change was primarily due to higher capital expenditures of $1.1 billion and higher 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, 2018 and 2017 were $(7.0) billion and $(6.1) billion, respectively. The change was primarily due to higher capital expenditures of $1.7 billion and higher funding of tax equity investments, partially offset by higher cash paid for acquisitions in 2017 of $1.0 billion. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

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 a 110-MW solar project and a 50-MW solar project, and the remaining 25% interest in a 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.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2019 were $3,124 million. Sources of cash totaled $5.4 billion and consisted of proceeds from subsidiary debt issuances totaling $4.7 billion and net proceeds from short-term debt of $684 million. Uses of cash totaled $2.3 billion and consisted mainly of $1.9 billion for repayments of subsidiary debt and repurchases of common stock of $293 million.

Net cash flows from financing activities for the year ended December 31, 2018 were $(174) million. Sources of cash totaled $5.6 billion and consisted of proceeds from BHE senior debt issuances of $3.2 billion and proceeds from subsidiary debt issuances totaling $2.4 billion. Uses of cash totaled $5.8 billion and consisted mainly of $2.4 billion for repayments of subsidiary debt, net repayments of short term debt of $1.9 billion, $1.0 billion for repayments of BHE senior debt and the purchase of redeemable noncontrolling interest of $131 million.

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.

Debt Repurchases

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.

Common Stock Transactions

For the years ended December 31, 2019, 2018 and 2017, BHE repurchased 447,712 shares of its common stock for $293 million, 177,381 shares of its common stock for $107 million and 35,000 shares of its common stock for $19 million, respectively.

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		
	2017	2018	2019	2020	2021	2022
PacifiCorp	$ 769	$ 1,257	$ 2,175	$ 2,788	$ 1,374	$ 2,392
MidAmerican Funding	1,776	2,332	2,810	1,861	1,027	877
NV Energy	456	503	657	675	468	526
Northern Powergrid	579	566	602	732	660	471
BHE Pipeline Group	286	427	687	489	470	421
BHE Transmission	334	270	247	522	321	260
BHE Renewables	323	817	122	106	65	71
HomeServices	37	47	54	44	38	35
BHE and Other	11	22	10	18	9	6
Total	$ 4,571	$ 6,241	$ 7,364	$ 7,235	$ 4,432	$ 5,059

	Historical			Forecast		
	2017	2018	2019	2020	2021	2022
Wind generation	$ 1,291	$ 2,740	$ 2,784	$ 2,355	$ 627	$ 717
Electric transmission	343	219	640	685	289	1,410
Other growth	689	715	828	845	682	431
Operating	2,248	2,567	3,112	3,350	2,834	2,501
Total	$ 4,571	$ 6,241	$ 7,364	$ 7,235	$ 4,432	$ 5,059

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 $1,486 million for 2019, $1,261 million for 2018 and $657 million for 2017. MidAmerican Energy placed in-service 1,019 MWs (nominal ratings) during 2019, 817 MWs (nominal ratings) during 2018 and 334 MWs (nominal ratings) during 2017. Wind XI, a 2,000-MW project, was completed in January 2020. Wind XII is a 591-MW project, including 201 MWs placed in-service in 2019 and facilities expected to be placed in-service by the end of 2020. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for 100% of PTCs available. PTCs from these projects are excluded from MidAmerican Energy's Iowa energy adjustment clause until these generation assets are reflected in base rates. Additionally, MidAmerican Energy continues to evaluate wind-powered and other renewable generating facilities that would not be subject to pre-approved ratemaking principles.
    - Repowering certain existing wind-powered generating facilities at MidAmerican Energy totaling $369 million for 2019, $422 million for 2018 and $514 million for 2017. The repowering projects entail the replacement of significant components of older turbines. Planned spending for the repowered generating facilities totals $136 million in 2020, $436 million in 2021 and $329 million in 2022. Of the 1,056 MWs of current repowering projects not in-service as of December 31, 2019, 649 MWs are currently expected to qualify for 80% of the federal PTCs available for ten years following each facility's return to service and 407 MWs are expected to qualify for 60% of such credits.
    - Construction of wind-powered generating facilities at PacifiCorp totaling $338 million for 2019, $9 million for 2018, and $5 million for 2017. A total of 1,190 MWs of new wind-powered generating facilities are expected to be placed in-service in 2020. Planned spending for the new wind-powered generating facilities totals $1,303 million in 2020, $79 million in 2021 and $388 million in 2022. The energy production from the new wind-powered generating facilities is expected to qualify for 100% of the federal PTCs available for ten years once the equipment is placed in service.

◦ Repowering certain existing wind-powered generating facilities at PacifiCorp totaling $585 million for 2019, $332 million for 2018 and $6 million for 2017. The repowering projects entail the replacement of significant components of older turbines. Certain repowering projects were placed in service in 2019 and the remaining repowering projects are expected to be placed in-service at various dates in 2020. Planned spending for the repowered generating facilities totals $87 million in 2020. The energy production from such repowered facilities is expected to qualify for 100% of the federal PTCs available for ten years following each facility's return to service.

◦ Construction of wind-powered generating facilities at BHE Renewables totaling $15 million for 2019, $717 million for 2018 and $109 million for 2017. BHE Renewables placed in-service 512 MWs during 2018.

- Electric transmission includes PacifiCorp's costs for the 140-mile 500-kV Aeolus-Bridger/Anticline transmission line, which is a major segment of PacifiCorp's Energy Gateway Transmission expansion program expected to be placed in service in 2020 and AltaLink's directly assigned projects from the AESO.
- Other growth includes projects to deliver power and services to new markets, new customer connections, enhancements to existing customer connections and investments in solar generation.
- Operating includes ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid, investments in routine expenditures for generation, transmission, distribution and other infrastructure needed to serve existing and expected demand and environmental spending relating to emissions control equipment and the management of coal combustion residuals.

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, 2019 (in millions):

	Payments Due By Periods				
	2020	2021-2022	2023-2024	2025 and After	Total
BHE senior debt	$ 350	$ 450	$ 900	$ 6,951	$ 8,651
BHE junior subordinated debentures	—	—	—	100	100
Subsidiary debt	2,189	2,650	3,223	22,821	30,883
Interest payments on long-term debt(1)	1,758	3,260	2,972	19,824	27,814
Short-term debt	3,214	—	—	—	3,214
Operating and finance lease liabilities	149	260	155	532	1,096
Interest payments on operating and finance lease liabilities(1)	69	115	86	395	665
Fuel, capacity and transmission contract commitments(1)	2,218	2,720	2,181	13,584	20,703
Construction commitments(1)	1,682	548	10	—	2,240
Easements(1)	62	138	142	2,259	2,601
Other(1)	718	753	586	1,655	3,712
Total contractual cash obligations	$ 12,409	$ 10,894	$ 10,255	$ 68,121	$ 101,679

(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 9), uncertain tax positions (Note 12) and asset retirement obligations (Note 14), 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 $1,619 million, $698 million and $403 million in 2019, 2018 and 2017, respectively, and has commitments as of December 31, 2019, subject to satisfaction of certain specified conditions, to provide equity contributions of $2.4 billion in 2020 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.

BHE Renewables' Counterparty Risk

On January 29, 2019, PG&E Corporation and Pacific Gas and Electric Company (the "PG&E Utility") (together "PG&E") filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of California ("PG&E Bankruptcy Filing"). The Company owns 100% of Topaz and owns a 49% interest in Agua Caliente. Topaz is a 550-MW solar photovoltaic electric power generating facility located in California. Topaz sells 100% of its energy, capacity and RECs generated from the facility to PG&E Utility under a 25-year wholesale power purchase agreement ("PPA") that is in effect until October 2039. As of December 31, 2019, the Company's consolidated balance sheet includes $1.0 billion of property, plant and equipment, net and $0.9 billion of non-recourse project debt related to Topaz. Agua Caliente is a 290-MW solar photovoltaic electric power generating facility located in Arizona. Agua Caliente sells 100% of its energy, capacity and RECs generated from the facility to PG&E Utility under a 25-year wholesale PPA that is in effect until June 2039. As of December 31, 2019, the Company's equity investment in Agua Caliente totals $73 million and the project has $0.8 billion of non-recourse project debt owed to the United States Department of Energy. The PG&E Bankruptcy Filing is an event of default under the Topaz PPA ("PPA Default"). PG&E paid in full the invoices for December 2018 deliveries and all amounts invoiced to date for post-petition energy deliveries for both Topaz and Agua Caliente. PG&E has not paid for the power delivered from January 1 through January 28, 2019. The Company continues to perform on its obligations and deliver renewable energy to the PG&E Utility, and PG&E has publicly stated it will pay suppliers in full under normal terms for post-petition goods and services received. The Company maintains that, in light of the current facts and circumstances, the PPA Default could not reasonably be expected to result in a material adverse effect under the Topaz indenture and, therefore, no default has occurred under the Topaz indenture. In July 2019, the California Governor signed AB 1054 into law. AB 1054 is comprehensive legislation addressing wildfire risk in the state of California that, among other items, authorizes a wildfire fund which would operate as an insurance fund to support the creditworthiness of electrical utilities, if certain utilities, including PG&E, participate by making the required contributions, among other things. In July 2019, PG&E notified the CPUC of its intent to participate in the insurance fund and such participation requires, among other items, PG&E to exit bankruptcy by June 30, 2020. The Company believes it is more likely than not that no impairment exists and current debt obligations will be met, as post-petition contractual revenue payments are expected to be paid by PG&E Utility to the Topaz and Agua Caliente projects. The Company will continue to monitor the situation, including continued receipt of future PG&E payments and the future risk of the PPAs being rejected or modified through the bankruptcy process.

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. 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. 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 United States Constitution. Both lawsuits were dismissed at the Northern District of Illinois, and the United States Court of Appeals for the Seventh Circuit affirmed the dismissals. On April 15, 2019, plaintiffs' petition seeking United States Supreme Court review of the case was denied.

On January 9, 2017, the Electric Power Supply Association ("EPSA") 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. When a resource is subjected to a MOPR, its offer price in the market is adjusted to effectively remove the revenues it receives through a government-provided financial support program, resulting in a higher offer that may not clear the capacity market. If the EPSA's requests are 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 filed protests at the FERC in response to each filing.

On December 19, 2019, the FERC issued an order in the PJM Interconnection, L.L.C. ("PJM") MOPR proceeding that broadly applies the MOPR to all new and existing resources, including nuclear, greatly expanding the breadth and scope of PJM's MOPR, effective as of PJM's next capacity auction. The FERC directed PJM to make a compliance filing within 90 days. The FERC has no deadline for acting on PJM's compliance filing. While the FERC included some limited exemptions in its order, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. In addition, the FERC provided no new mechanism for accommodating state-supported resources other than the existing Fixed Resource Requirement ("FRR") mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. Unless Illinois can implement an FRR program in their PJM zones, the MOPR will apply to Exelon Generation's nuclear plants in those states receiving a benefit under the Illinois zero emissions program, including Quad Cities Station, resulting in higher offers for those units that may not clear the capacity market.

On January 21, 2020, Exelon Generation, PJM and a number of other entities submitted individual requests for rehearing of the FERC's December 19, 2019 order on the PJM MOPR. Exelon Generation is currently working with PJM and other stakeholders to pursue the FRR option prior to the next capacity auction in PJM. If Illinois implements the FRR option, Quad Cities Station could be removed from PJM's capacity auction and instead supply capacity and be compensated under the FRR program. Implementing the FRR program in Illinois will require both legislative and regulatory changes. MidAmerican Energy cannot predict whether such legislative and regulatory changes can be implemented prior to the next capacity auction in PJM or their potential impact on the continued operation of Quad Cities Station.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding climate change, RPS, air and water quality, emissions performance standards, 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.

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, 2019, 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, 2019, the Company would have been required to post $390 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.

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, 2019, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.4 billion, unused revolving credit facilities of $119 million and letters of credit outstanding of $88 million. As of December 31, 2019, the Company's pro-rata share of such short- and long-term debt was $1.2 billion, unused revolving credit facilities was $60 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 $2.9 billion and total regulatory liabilities were $7.3 billion as of December 31, 2019. Refer to Note 7 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.

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, 2019, the Company had $77 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, 2019 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, 2019. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. Refer to Note 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's goodwill.

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2019, 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, 2019, the Company recognized a net liability totaling $21 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2019, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $600 million and in AOCI totaled $570 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 13 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, 2019.

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 13 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, 2019						
Benefit Obligations:						
Discount rate	$ (143)	$ 158	$ (27)	$ 30	$ (190)	$ 171
Effect on 2019 Periodic Cost:						
Discount rate	$ (1)	$ 2	$ 1	$ (1)	$ (19)	$ 19
Expected rate of return on plan assets	(12)	12	(4)	2	(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 commissions. 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 12 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers in certain state and provincial jurisdictions. As of December 31, 2019, these amounts were recognized as a net regulatory liability of $3.4 billion and will be included in regulated rates when the temporary differences reverse.
The Company has not established deferred income taxes on its undistributed foreign earnings that have been determined by management to be reinvested indefinitely; however, the Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of the Company's undistributed foreign earnings were repatriated, the dividends may be subject to taxation in the United States but the tax is not expected to be material.

Revenue Recognition - Unbilled Revenue

Revenue recognized is equal to what the Company has the right to invoice as it corresponds directly with the value to the customer of the Company's performance to date and includes billed and unbilled amounts. The determination of customer invoices 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 $638 million as of December 31, 2019. 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.

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 manage 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 $79 million and $59 million, respectively, as of December 31, 2019 and 2018, 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, 2019:			
Not designated as hedging contracts	$ 16	$ 57	$ (24)
Designated as hedging contracts	(21)	(1)	(41)
Total commodity derivative contracts	$ (5)	$ 56	$ (65)
As of December 31, 2018:			
Not designated as hedging contracts	$ 5	$ 34	$ (12)
Designated as hedging contracts	5	37	(21)
Total commodity derivative contracts	$ 10	$ 71	$ (33)

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, 2019 and 2018, a net regulatory asset of $77 million and $110 million, respectively, was recorded related to the net derivative asset of $16 million and $5 million, respectively. The difference between the net regulatory asset and the net derivative asset 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 9, 10, 11, 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, 2019 and 2018, the Company had short- and long-term variable-rate obligations totaling $4.8 billion and $4.3 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, 2019 and 2018.

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, 2019 and 2018, the Company had variable-to-fixed interest rate swaps with notional amounts of $380 million and $637 million, respectively, and £141 million and £161 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2019 and 2018, the Company had mortgage commitments, net, with notional amounts of $913 million and $326 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 liability of $5 million as of December 31, 2019 and a net derivative liability of $8 million as of December 31, 2018. 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, 2019 and 2018, the Company's investment in BYD Company Limited common stock represented approximately 69% and 79%, respectively, of the total fair value of the Company's equity securities. The majority of the Company's remaining equity securities are held in a trust related to the decommissioning of nuclear generation assets and the 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, 2019 and 2018 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, 2019	$ 1,122	30% increase	$ 1,459	1%
		30% decrease	785	(1)
As of December 31, 2018	$ 1,435	30% increase	$ 1,866	1%
		30% decrease	1,005	(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, 2019, 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 $452 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 $26 million in 2019.

BHE Canada's functional currency is the Canadian dollar. As of December 31, 2019, 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 $336 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for BHE Canada of $17 million in 2019.

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, 2019, PacifiCorp's aggregate credit exposure with wholesale energy supply and marketing counterparties included counterparties having non-investment grade, internally rated credit ratings. Substantially all of these non-investment grade, internally rated counterparties are associated with long-duration solar and wind power purchase agreements from facilities that have not yet achieved commercial operation and for which PacifiCorp has no obligation should the facilities not achieve commercial operation.

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, 2019, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2019, 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 2019, RWE Npower PLC and certain of its affiliates and British Gas Trading Limited represented approximately 17% and 12%, 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.

BHE Canada

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 $706 million for the year ended December 31, 2019.

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 2019 and 2043. 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. On January 29, 2019, a customer of certain BHE Renewables' solar projects filed for chapter 11 bankruptcy protection. See BHE Renewables' Counterparty Risk in Item 7 of this Form 10-K for additional information. Total operating revenue for BHE Renewables was $932 million for the year ended December 31, 2019.

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, 2019, 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 the 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, 2019 and 2018, 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, 2019, and the related notes and the schedules listed in the Index at Item 15(a)(2) (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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for leases in 2019 due to the adoption of ASU 2016-02 "Leases". In 2018, the Company changed its method of accounting for investments in equity securities (excluding equity method investments) due to the adoption of ASU 2016-01 "Financial Instruments - Recognition and Measurement of Financial Assets and Financial Liabilities".

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 21, 2020

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,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,040	$ 627
Restricted cash and cash equivalents	212	227
Trade receivables, net	1,910	2,038
Inventories	873	844
Mortgage loans held for sale	1,039	468
Other current assets	839	943
Total current assets	5,913	5,147
Property, plant and equipment, net	73,305	68,087
Goodwill	9,722	9,595
Regulatory assets	2,766	2,896
Investments and restricted cash and cash equivalents and investments	6,255	4,903
Other assets	2,090	1,561
Total assets	$ 100,051	$ 92,189

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,	
	2019	**2018**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,839	$ 1,809
Accrued interest	493	469
Accrued property, income and other taxes	537	599
Accrued employee expenses	285	275
Short-term debt	3,214	2,516
Current portion of long-term debt	2,539	2,081
Other current liabilities	1,350	1,021
Total current liabilities	10,257	8,770
BHE senior debt	8,231	8,577
BHE junior subordinated debentures	100	100
Subsidiary debt	28,483	25,492
Regulatory liabilities	7,100	7,346
Deferred income taxes	9,653	9,047
Other long-term liabilities	3,649	3,134
Total liabilities	67,473	62,466
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	6,389	6,371
Long-term income tax receivable	(530)	(457)
Retained earnings	28,296	25,624
Accumulated other comprehensive loss, net	(1,706)	(1,945)
Total BHE shareholders' equity	32,449	29,593
Noncontrolling interests	129	130
Total equity	32,578	29,723
Total liabilities and equity	$ 100,051	$ 92,189

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,		
	2019	**2018**	**2017**
Operating revenue:			
Energy	$ 15,371	$ 15,573	$ 15,171
Real estate	4,473	4,214	3,443
Total operating revenue	19,844	19,787	18,614
Operating expenses:			
Energy:			
Cost of sales	4,586	4,769	4,518
Operations and maintenance	3,318	3,440	3,210
Depreciation and amortization	2,965	2,933	2,580
Property and other taxes	574	573	555
Real estate	4,251	4,000	3,229
Total operating expenses	15,694	15,715	14,092
Operating income	4,150	4,072	4,522
Other income (expense):			
Interest expense	(1,912)	(1,838)	(1,841)
Capitalized interest	77	61	45
Allowance for equity funds	173	104	76
Interest and dividend income	117	113	111
(Losses) gains on marketable securities, net	(288)	(538)	14
Other, net	97	(9)	(420)
Total other income (expense)	(1,736)	(2,107)	(2,015)
Income before income tax benefit and equity (loss) income	2,414	1,965	2,507
Income tax benefit	(598)	(583)	(554)
Equity (loss) income	(44)	43	(151)
Net income	2,968	2,591	2,910
Net income attributable to noncontrolling interests	18	23	40
Net income attributable to BHE shareholders	$ 2,950	$ 2,568	$ 2,870

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,		
	2019	**2018**	**2017**
Net income	$ 2,968	$ 2,591	$ 2,910
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $15, $8 and $9	(59)	25	64
Foreign currency translation adjustment	327	(494)	546
Unrealized gains on marketable securities, net of tax of $-, $- and $270	—	—	500
Unrealized (losses) gains on cash flow hedges, net of tax of $8, $1 and $(7)	(29)	7	3
Total other comprehensive income (loss), net of tax	239	(462)	1,113
Comprehensive income	3,207	2,129	4,023
Comprehensive income attributable to noncontrolling interests	18	23	40
Comprehensive income attributable to BHE shareholders	$ 3,189	$ 2,106	$ 3,983

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 Shares	Common Stock	Additional Paid-in Capital	Long-term Income Tax Receivable	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2016	77	$ —	$ 6,390	$ —	$ 19,448	$ (1,511)	$ 136	$ 24,463
Net income	—	—	—	—	2,870	—	22	2,892
Other comprehensive loss	—	—	—	—	—	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
Adoption of ASU 2016-01	—	—	—	—	1,085	(1,085)	—	—
Net income	—	—	—	—	2,568	—	20	2,588
Other comprehensive income	—	—	—	—	—	(462)	—	(462)
Reclassification of long-term income tax receivable	—	—	—	(609)	—	—	—	(609)
Long-term income tax receivable adjustments	—	—	—	152	(135)	—	—	17
Common stock purchases	—	—	(6)	—	(101)	—	—	(107)
Distributions	—	—	—	—	—	—	(23)	(23)
Other equity transactions	—	—	9	—	1	—	1	11
Balance, December 31, 2018	77	—	6,371	(457)	25,624	(1,945)	130	29,723
Net income	—	—	—	—	2,950		18	2,968
Other comprehensive income	—	—	—	—	—	239	—	239
Long-term income tax receivable adjustments	—	—	33	(73)	—	—	—	(40)
Common stock purchases	—	—	(15)	—	(278)	—	—	(293)
Distributions	—	—		—	—	—	(22)	(22)
Other equity transactions	—	—		—	—	—	3	3
Balance, December 31, 2019	77	$ —	$ 6,389	$ (530)	$ 28,296	$ (1,706)	$ 129	$ 32,578

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,		
	2019	**2018**	**2017**
Cash flows from operating activities:			
Net income	$ 2,968	$ 2,591	$ 2,910
Adjustments to reconcile net income to net cash flows from operating activities:			
Losses (gains) on marketable securities, net	288	538	(14)
Losses (gains) on other items, net	43	56	455
Depreciation and amortization	3,011	2,984	2,646
Allowance for equity funds	(173)	(104)	(76)
Equity loss (income), net of distributions	93	45	260
Changes in regulatory assets and liabilities	153	196	31
Deferred income taxes and amortization of investment tax credits	290	8	19
Other, net	23	67	12
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(372)	72	(74)
Derivative collateral, net	(25)	27	(22)
Pension and other postretirement benefit plans	(51)	(54)	(91)
Accrued property, income and other taxes	(16)	199	(28)
Accounts payable and other liabilities	(26)	145	50
Net cash flows from operating activities	6,206	6,770	6,078
Cash flows from investing activities:			
Capital expenditures	(7,364)	(6,241)	(4,571)
Acquisitions, net of cash acquired	(27)	(106)	(1,113)
Purchases of marketable securities	(262)	(329)	(190)
Proceeds from sales of marketable securities	238	287	202
Equity method investments	(1,617)	(683)	(395)
Other, net	69	83	(12)
Net cash flows from investing activities	(8,963)	(6,989)	(6,079)
Cash flows from financing activities:			
Proceeds from BHE senior debt	—	3,166	—
Repayments of BHE senior debt and junior subordinated debentures	—	(1,045)	(2,323)
Common stock purchases	(293)	(107)	(19)
Proceeds from subsidiary debt	4,699	2,352	1,763
Repayments of subsidiary debt	(1,914)	(2,422)	(1,000)
Net proceeds from (repayments of) short-term debt	684	(1,946)	2,361
Tender offer premium paid	—	—	(435)
Purchase of redeemable noncontrolling interest	—	(131)	—
Other, net	(52)	(41)	(73)
Net cash flows from financing activities	3,124	(174)	274
Effect of exchange rate changes	18	(7)	7
Net change in cash and cash equivalents and restricted cash and cash equivalents	385	(400)	280
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	883	1,283	1,003
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 1,268	$ 883	$ 1,283

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 ("BHE Canada") (which primarily consists of AltaLink, L.P. ("AltaLink")) 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 wind, solar, geothermal and hydroelectric projects, the 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 AltaLink (the "Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit the Regulated Businesses' ability to recover their costs. The Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at 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 Cash Equivalents 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 cash and cash equivalents consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements and debt service obligations for certain of the Company's nonregulated renewable energy projects. Restricted amounts are included in restricted cash and cash equivalents and investments and restricted cash and cash equivalents and investments on the Consolidated Balance Sheets.

Investments

Fixed Maturity Securities

The Company's management determines the appropriate classification of investments in fixed maturity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments and restricted cash and cash equivalents 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 investments 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 fixed maturity 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 investments are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity investments are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The difference between the original cost and maturity value of a fixed maturity security is amortized to earnings using the interest method.

Investment gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired with respect to securities classified as available-for-sale. If the value of a fixed maturity investment declines to below amortized cost and the decline is deemed other than temporary, the amortized cost of the investment is reduced to fair value, with a corresponding charge to earnings. 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 other comprehensive income (loss) ("OCI"). For regulated fixed maturity investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Equity Securities

Investments in equity securities are carried at fair value with changes in fair value recognized in earnings as a component of gains (losses) on marketable securities, net. Prior to January 1, 2018, substantially all of the Company's equity security investments were classified as available-for-sale with changes in fair value recognized in OCI, net of income taxes. All changes in fair value of equity 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.

Equity Method Investments

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 the 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 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.

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 collectability 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, 2019 and 2018, the allowance for doubtful accounts totaled $44 million and $42 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 $257 million and $273 million as of December 31, 2019 and 2018, respectively, and materials and supplies totaling $616 million and $571 million as of December 31, 2019 and 2018, 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 $2 million and $14 million higher as of December 31, 2019 and 2018, respectively.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction-related materials, 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.

Leases

The Company has non-cancelable operating leases primarily for office space, office equipment, generating facilities, land and rail cars and finance leases consisting primarily of transmission assets, generating facilities and vehicles. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company does not include options in its lease calculations unless there is a triggering event indicating the Company is reasonably certain to exercise the option. The Company’s accounting policy is to not recognize lease obligations and corresponding right-of-use assets for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with ASC 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

The Company's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

The Company's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly. The right-of-use assets and lease liabilities for finance leases as of December 31, 2018 have been reclassified from property, plant and equipment, net and current portion of long-term and subsidiary debt, respectively, to conform to the current period presentation.

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 2019, 2018 and 2017, 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

Customer Revenue

The Company uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. 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. In the event one of the parties to a contract has performed before the other, the Company would recognize a contract asset or contract liability depending on the relationship between the Company's performance and the customer's payment.

Energy Products and Services

A majority of the Company's energy revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. The Company's energy revenue that is nonregulated primarily relates to the Company's renewable energy business.

Revenue recognized is equal to what the Company has the right to invoice as it corresponds directly with the value to the customer of the Company's performance to date and includes billed and unbilled amounts. As of December 31, 2019 and 2018, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $638 million and $554 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. 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.

Real Estate Services

The Company's HomeServices reportable segment consists of separate brokerage, mortgage and franchise businesses. Rates charged for brokerage, mortgage and franchise real estate services are established through contractual arrangements that establish the transaction price and the allocation of the price amongst the separate performance obligations.

The full-service residential real estate brokerage business has performance obligations to deliver integrated real estate services including brokerage services, title and closing services, property and casualty insurance, home warranties, relocation services, and other home-related services to customers. All performance obligations related to the full-service residential real estate brokerage business are satisfied in less than one year at the point in time when a real estate transaction is closed or when services are provided. 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. Payments for amounts billed are generally due from the customer at closing.

The franchise business operates a network that has performance obligations to provide the right to use certain brand names and other related service marks as well as to provide orientation programs, training and consultation services, advertising programs and other services to its franchisees. The performance obligations related to the franchise business are satisfied over time or when the services are provided. Franchise royalty fees are sales-based variable consideration and are based on a percentage of commissions earned by franchisees on real estate sales, which are recognized when the sale closes. Meetings and training revenue, referral fees, late fees, service fees and franchise termination fees are earned when services have been completed. Payments for amounts billed are generally due from the franchisee within 30 days of billing.

Other Revenue

Energy Products and Services

Other revenue consists primarily of revenue related to power purchase agreements not considered Customer Revenue as they are recognized in accordance with Accounting Standards Codification ("ASC") 815, "Derivatives and Hedging" and ASC 842, "Leases" and certain non tariff-based revenue approved by the regulator that is not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers."

Real Estate Service

Other revenue consists primarily of revenue related to the mortgage business. 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. These amounts are not considered Customer Revenue as they are recognized in accordance with ASC 815, "Derivatives and Hedging," ASC 825, "Financial Instruments" and ASC 860, "Transfers and Servicing."

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

The Company's provision for income taxes has been computed on a stand-alone basis. Berkshire Hathaway includes the Company in its consolidated United States federal and Iowa state income tax returns and the majority of the Company's United States federal income tax is remitted to or received from Berkshire Hathaway. The Company records the deferred income tax assets associated with the state of Iowa net operating loss carryforward as a long-term income tax receivable from Berkshire Hathaway as a component of BHE's shareholders' equity due to the long-term related-party nature of the income tax receivable.

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 associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with income tax benefits and expense for 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 commissions.

The Company has not established deferred income taxes on its undistributed foreign earnings that have been determined by management to be reinvested indefinitely; however, the Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of the Company's undistributed foreign earnings were repatriated, the dividends may be subject to taxation in the United States but the tax is not expected to be material.

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 commissions. 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 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("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 on 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. Following the issuance of ASU No. 2016-02, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2016-02 but did not change the core principle of the guidance. The Company has elected to utilize various practical expedients available to adopt ASU No. 2016-02, including (1) the package of three not requiring a reassessment of (i) whether any expired or existing contracts are or contain leases; (ii) the lease classification for any expired or existing leases; and (iii) initial direct costs for any existing leases; (2) using hindsight in determining the lease term; and (3) not requiring a reassessment of whether existing or expired land easements that were not previously accounted for as leases under ASC Topic 840 are or contain a lease under ASC Topic 842. The Company adopted this guidance for all applicable contracts in-effect as of January 1, 2019 under a modified retrospective method and the adoption did not have a cumulative effect impact at the date of initial adoption.

(3) Business Acquisitions

The Company completed various acquisitions, which primarily related to residential real estate brokerage businesses and, in 2017, development and construction costs for a110-megawatt ("MW")solar project and a 50-MW solar project and the remaining 25% interest in a natural gas-fueled generation facility at Nevada Power, totaling $27 million in 2019, $106 million in 2018 and $1.1 billion in 2017. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed and the 2017 acquisitions resulted in acquired assets of $1.1 billion, assumed liabilities of $487 million and recognized goodwill of $508 million. The acquired assets, assumed liabilities and recognized goodwill for the 2019 and 2018 acquisitions were not material. Additionally, in April 2018, HomeServices acquired the remaining 33.3% interest in a real estate brokerage franchise business from the noncontrolling interest member at a contractually determined option exercise price totaling $131 million.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2019	2018
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 81,127	$ 76,707
Interstate natural gas pipeline assets	3-80 years	8,165	7,524
		89,292	84,231
Accumulated depreciation and amortization		(26,353)	(25,894)
Regulated assets, net		62,939	58,337
Nonregulated assets:			
Independent power plants	5-30 years	6,983	6,826
Other assets	3-30 years	1,834	1,424
		8,817	8,250
Accumulated depreciation and amortization		(2,183)	(1,610)
Nonregulated assets, net		6,634	6,640
Net operating assets		69,573	64,977
Construction work-in-progress		3,732	3,110
Property, plant and equipment, net		$ 73,305	$ 68,087

Construction work-in-progress includes $3.6 billion and $2.9 billion as of December 31, 2019 and 2018, respectively, related to the construction of regulated assets.

(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, 2019 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67%	$ 1,476	$ 677	$ 9
Hunter No. 1	94	484	193	1
Hunter No. 2	60	305	121	2
Wyodak	80	473	243	1
Colstrip Nos. 3 and 4	10	254	137	2
Hermiston	50	181	92	5
Craig Nos. 1 and 2	19	368	252	—
Hayden No. 1	25	75	39	—
Hayden No. 2	13	43	23	—
Transmission and distribution facilities	Various	808	255	103
Total PacifiCorp		4,467	2,032	123
MidAmerican Energy:				
Louisa No. 1	88%	834	458	7
Quad Cities Nos. 1 and 2(1)	25	729	424	11
Walter Scott, Jr. No. 3	79	930	392	5
Walter Scott, Jr. No. 4(2)	60	316	131	1
George Neal No. 4	41	316	171	2
Ottumwa No. 1	52	634	229	19
George Neal No. 3	72	489	238	4
Transmission facilities	Various	258	95	—
Total MidAmerican Energy		4,506	2,138	49
NV Energy:				
Navajo	11%	13	2	—
Valmy	50	390	271	—
Transmission facilities	Various	70	29	—
On Line Transmission Line	25	159	24	—
Total NV Energy		632	326	—
BHE Pipeline Group - common facilities	Various	266	157	—
Total		$ 9,871	$ 4,653	$ 172

(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 $458 million and $94 million, respectively.

(6) Leases

The following table summarizes the Company's leases recorded on the Consolidated Balance Sheet (in millions):

	As of December 31, 2019
Right-of-use assets:	
Operating leases	$ 525
Finance leases	504
Total right-of-use assets	$ 1,029
Lease liabilities:	
Operating leases	$ 577
Finance leases	519
Total lease liabilities	$ 1,096

The following table summarizes the Company's lease costs (in millions):

	Year Ended December 31, 2019
Variable	$ 623
Operating	170
Finance:	
Amortization	16
Interest	41
Short-term	7
Total lease costs	$ 857
Weighted-average remaining lease term (years):	
Operating leases	7.6
Finance leases	28.8
Weighted-average discount rate:	
Operating leases	5.2%
Finance leases	8.6%

The following table summarizes the Company's supplemental cash flow information relating to leases (in millions):

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ (153)
Operating cash flows from finance leases	(42)
Financing cash flows from finance leases	(19)
Right-of-use assets obtained in exchange for lease liabilities:	
Operating leases	$ 82
Finance leases	14

The Company has the following remaining lease commitments as of (in millions):

	December 31, 2019		
	Operating	Finance	Total
2020	$ 147	$ 71	$ 218
2021	126	77	203
2022	102	70	172
2023	73	59	132
2024	50	59	109
Thereafter	202	725	927
Total undiscounted lease payments	700	1,061	1,761
Less - amounts representing interest	(123)	(542)	(665)
Lease liabilities	$ 577	$ 519	$ 1,096

	December 31, 2018[(1)]		
	Operating	Capital	Total
2019	$ 147	$ 69	$ 216
2020	128	68	196
2021	110	73	183
2022	87	67	154
2023	61	56	117
Thereafter	159	772	931
Total undiscounted lease payments	$ 692	$ 1,105	$ 1,797

(1) Amounts included for comparability and accounted for in accordance with ASC 840, "Leases".

(7) 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	2019	2018
Employee benefit plans[1]	15 years	$ 667	$ 773
Asset retirement obligations	Various	445	375
Asset disposition costs	Various	391	358
Deferred income taxes[2]	Various	223	196
Deferred operating costs	11 years	134	141
Deferred net power costs	2 years	110	103
Unrealized loss on regulated derivative contracts	3 years	78	120
Unamortized contract values	4 years	60	79
Abandoned projects	3 years	58	134
Other	Various	715	788
Total regulatory assets		$ 2,881	$ 3,067
Reflected as:			
Current assets		$ 115	$ 171
Noncurrent assets		2,766	2,896
Total regulatory assets		$ 2,881	$ 3,067

(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 $1.4 billion and $1.3 billion as of December 31, 2019 and 2018, 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	2019	2018
Deferred income taxes[1]	Various	$ 3,611	$ 3,923
Cost of removal[2]	27 years	2,370	2,426
Levelized depreciation	29 years	304	329
Asset retirement obligations	33 years	241	163
Impact fees	2 years	72	88
Other	Various	713	577
Total regulatory liabilities		$ 7,311	$ 7,506
Reflected as:			
Current liabilities		$ 211	$ 160
Noncurrent liabilities		7,100	7,346
Total regulatory liabilities		$ 7,311	$ 7,506

(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 12 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.

(8) Investments and Restricted Cash and Cash Equivalents and Investments

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

	2019	2018
Investments:		
BYD Company Limited common stock	$ 1,122	$ 1,435
Rabbi trusts	410	371
Other	187	168
Total investments	1,719	1,974
Equity method investments:		
BHE Renewables tax equity investments	3,130	1,661
Electric Transmission Texas, LLC	555	527
Bridger Coal Company	81	99
Other	181	153
Total equity method investments	3,947	2,440
Restricted cash and cash equivalents and investments:		
Quad Cities Station nuclear decommissioning trust funds	599	504
Other restricted cash and cash equivalents	230	256
Total restricted cash and cash equivalents and investments	829	760
Total investments and restricted cash and cash equivalents and investments	$ 6,495	$ 5,174
Reflected as:		
Other current assets	$ 240	$ 271
Noncurrent assets	6,255	4,903
Total investments and restricted cash and cash equivalents and investments	$ 6,495	$ 5,174

Investments

BHE's investment in BYD Company Limited common stock is accounted for as a marketable security with changes in fair value recognized in net income.

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.

(Losses) gains on marketable securities, net recognized during the period consists of the following (in millions):

	Years Ended December 31,	
	2019	2018
Unrealized losses recognized on marketable securities still held at the reporting date	$ (290)	$ (540)
Net gains recognized on marketable securities sold during the period	2	2
Losses on marketable securities, net	$ (288)	$ (538)

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 $1,619 million, $698 million and $403 million in 2019, 2018 and 2017, respectively, and has commitments as of December 31, 2019, subject to satisfaction of certain specified conditions, to provide equity contributions of $2.4 billion in 2020 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 12 for discussion of 2017 Tax Reform impacts to equity earnings recorded for the year ended December 31, 2017.

Restricted 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 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.

(9) 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	BHE Canada	Other	Total[1]
2019:								
Credit facilities	$ 3,500	$ 1,200	$ 1,309	$ 650	$ 199	$ 674	$ 1,880	$ 9,412
Less:								
Short-term debt	(1,590)	(130)	—	—	—	(211)	(1,283)	(3,214)
Tax-exempt bond support and letters of credit	—	(256)	(370)	—	—	(3)	—	(629)
Net credit facilities	$ 1,910	$ 814	$ 939	$ 650	$ 199	$ 460	$ 597	$ 5,569
2018:								
Credit facilities[2]	$ 3,500	$ 1,200	$ 1,309	$ 650	$ 231	$ 639	$ 1,585	$ 9,114
Less:								
Short-term debt	(983)	(30)	(240)	—	(77)	(345)	(841)	(2,516)
Tax-exempt bond support and letters of credit	—	(89)	(370)	(80)	—	(4)	—	(543)
Net credit facilities	$ 2,517	$ 1,081	$ 699	$ 570	$ 154	$ 290	$ 744	$ 6,055

(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 the drawn uncommitted credit facilities totaling $39 million at Northern Powergrid.

As of December 31, 2019, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

BHE has a $3.5 billion unsecured credit facility expiring in June 2022 with one remaining one-year extension option subject to lender consent. This credit facility, which is for general corporate purposes, supports BHE's commercial paper program and provides for the issuance of letters of credit, has a variable interest rate 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, 2019 and 2018, the weighted average interest rate on commercial paper borrowings outstanding was 1.91% and 2.76%, respectively. This credit facility requires 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, 2019 and 2018, BHE had $107 million and $115 million, respectively, of letters of credit outstanding. These letters of credit primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC expiring through April 2021 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.

PacifiCorp

PacifiCorp has a $600 million unsecured credit facility expiring in June 2022 and a $600 million unsecured credit facility expiring in June 2022 with one remaining 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, 2019 and 2018, the weighted average interest rate on commercial paper borrowings outstanding was 2.05% and 2.85%, 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, 2019 and 2018, PacifiCorp had $13 million and $184 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2019 and 2018, $13 million and $14 million, respectively, support certain transactions required by third parties and generally 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 2022. The credit facility supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations, provides for the issuance of letters of credit and 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. MidAmerican Energy has a $400 million unsecured credit facility that expires in August 2020 and has a variable interest rate based on the Eurodollar rate or a base rate, at MidAmerican Energy's option, plus a spread. As of December 31, 2018, MidAmerican Energy had a $400 million unsecured credit facility expiring November 2019, which it terminated in January 2019.

MidAmerican Energy had commercial paper borrowings outstanding of $- million as of December 31, 2019, and $240 million with a weighted average interest rate of 2.49% as of December 31, 2018. 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 2022 and Sierra Pacific has a $250 million secured credit facility expiring in June 2022. 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 October 2022. 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

AltaLink has a C$500 million secured revolving term credit facility expiring in December 2023 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 AltaLink's option, based on AltaLink's credit ratings for its senior secured long-term debt securities. In addition, AltaLink has a C$75 million secured revolving term credit facility expiring in December 2023 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 AltaLink's option, based on AltaLink's credit ratings for its senior secured long-term debt securities.

As of December 31, 2019 and 2018, AltaLink had $192 million and $281 million outstanding under these facilities at a weighted average interest rate of 2.16% and 2.26%, 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 2023 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 to a maximum of C$10 million, 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 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, 2019 and 2018, AltaLink Investments, L.P. had $19 million and $64 million outstanding under this facility at a weighted average interest rate of 3.08% and 3.25%, respectively. The credit facility requires the consolidated total debt to capitalization to not exceed 0.8 to 1.0 and earnings before interest, taxes, depreciation and amortization to interest expense for the four fiscal quarters ended to not be less than 2.25 to 1.0 measured as of the last day of each quarter.

In January 2020, AltaLink and AltaLink Investments, L.P. extended, with lender consent, the expiration dates for the existing credit facilities to December 2024.

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, 2019 and 2018, HomeServices had $318 million and $404 million, respectively, outstanding under its credit facility with a weighted average interest rate of 3.29% and 3.94%, respectively.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $1.3 billion and $985 million as of December 31, 2019 and 2018, respectively, used for mortgage banking activities that expire beginning in January 2020 through December 2020. 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, 2019 and 2018, HomeServices had $965 million and $436 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 3.51% and 4.42%, respectively.

BHE Renewables Letters of Credit

As of December 31, 2019 and 2018, certain renewable projects collectively have letters of credit outstanding of $373 million and $322 million, respectively, primarily in support of the power purchase agreements and large generator interconnection agreements associated with the projects.

(10) 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	2019	2018
2.40% Senior Notes, due 2020	$ 350	$ 349	$ 349
2.375% Senior Notes, due 2021	450	448	448
2.80% Senior Notes, due 2023	400	398	398
3.75% Senior Notes, due 2023	500	498	498
3.50% Senior Notes, due 2025	400	398	398
3.25% Senior Notes, due 2028	600	594	594
8.48% Senior Notes, due 2028	256	259	257
6.125% Senior Bonds, due 2036	1,670	1,661	1,661
5.95% Senior Bonds, due 2037	550	548	547
6.50% Senior Bonds, due 2037	225	223	222
5.15% Senior Notes, due 2043	750	740	740
4.50% Senior Notes, due 2045	750	738	738
3.80% Senior Notes, due 2048	750	737	737
4.45% Senior Notes, due 2049	1,000	990	990
Total BHE Senior Debt	$ 8,651	$ 8,581	$ 8,577
Reflected as:			
Current liabilities		$ 350	$ —
Noncurrent liabilities		8,231	8,577
Total BHE Senior Debt		$ 8,581	$ 8,577

Junior Subordinated Debentures

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

	Par Value	2019	2018
Junior subordinated debentures, due 2057	100	100	100
Total BHE junior subordinated debentures - noncurrent	$ 100	$ 100	$ 100

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 was $5 million for each of the years ended December 31, 2019 and 2018.

(11) 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, 2019, all subsidiaries were in compliance with their long-term debt covenants. On January 29, 2019, PG&E Corporation and Pacific Gas and Electric Company (the "PG&E Utility") (together "PG&E") filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of California. As a result, the Company does not expect to receive distributions from Topaz Solar Farms LLC ("Topaz") or Agua Caliente Solar, LLC ("Agua Caliente") in the near term.

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	2019	2018
PacifiCorp	$ 7,705	$ 7,658	$ 7,015
MidAmerican Funding	7,515	7,427	5,597
NV Energy	3,836	3,821	3,817
Northern Powergrid	3,234	3,221	2,626
BHE Pipeline Group	1,250	1,247	1,042
BHE Transmission	3,891	3,879	3,842
BHE Renewables	3,239	3,206	3,401
HomeServices	213	213	233
Total subsidiary debt	$ 30,883	$ 30,672	$ 27,573
Reflected as:			
Current liabilities		$ 2,189	$ 2,081
Noncurrent liabilities		28,483	25,492
Total subsidiary debt		$ 30,672	$ 27,573

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	2019	2018
First mortgage bonds:			
2.95% to 8.53%, due through 2024	$ 1,899	$ 1,895	$ 2,244
3.35% to 6.71%, due 2025 to 2026	350	349	348
3.50% to 7.70%, due 2029 to 2031	700	696	298
5.25% to 6.35%, due 2034 to 2038	2,350	2,338	2,338
4.10% to 6.00%, due 2039 to 2042	950	939	939
4.13% to 4.15%, due 2049 to 2050	1,200	1,186	593
Variable-rate series, tax-exempt bond obligations (2019-1.60% to 1.80%; 2018-1.67% to 1.85%):			
Due 2020	38	38	38
Due 2024(1)(2)	143	143	142
Due 2025(1)	25	24	25
Due 2024 to 2025(2)	50	50	50
Total PacifiCorp	$ 7,705	$ 7,658	$ 7,015

(1) Supported by $170 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2018. These arrangements were canceled in 2019.

(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 $29 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2019.

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	2019	2018
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 239	$ 219	$ 217
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (weighted average interest rate- 2019-1.66%, 2018-1.74%), due 2023-2047	$ 370	$ 368	$ 368
First Mortgage Bonds:			
2.40%, due 2019	—	—	500
3.70%, due 2023	250	249	249
3.50%, due 2024	500	501	501
3.10%, due 2027	375	373	372
3.65%, due 2029	850	864	—
4.80%, due 2043	350	346	346
4.40%, due 2044	400	395	394
4.25%, due 2046	450	445	445
3.95%, due 2047	475	470	470
3.65%, due 2048	700	688	688
4.25%, due 2049	900	872	—
3.15%, due 2050	600	591	—
Notes:			
6.75% Series, due 2031	400	396	396
5.75% Series, due 2035	300	298	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligation, 4.45% and 3.42% due through 2035 and 2036, respectively	6	4	5
Total MidAmerican Energy	7,276	7,208	5,380
Total MidAmerican Funding	$ 7,515	$ 7,427	$ 5,597

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as amended by the First Supplemental Indenture dated as of September 19, 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, 2019, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $20 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, 2019 and 2018. 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	2019	2018
NV Energy:			
6.250% Senior Notes, due 2020	$ 315	$ 321	$ 330
Nevada Power:			
General and refunding mortgage securities:			
7.125% Series V, due 2019	—	—	500
2.750%, Series BB, due 2020	575	575	574
3.700%, Series CC, due 2029	500	496	—
6.650% Series N, due 2036	367	360	360
6.750% Series R, due 2037	349	348	348
5.375% Series X, due 2040	250	249	248
5.450% Series Y, due 2041	250	245	244
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.800% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	40
1.600% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
1.600% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Total Nevada Power	2,384	2,364	2,366
Sierra Pacific:			
General and refunding mortgage securities:			
3.375% Series T, due 2023	250	249	249
2.600% Series U, due 2026	400	396	396
6.750% Series P, due 2037	252	256	256
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.250% Pollution Control Series 2016A, due 2029	—	—	20
1.850% Pollution Control Series 2016B, due 2029(2)	30	29	—
1.500% Gas Facilities Series 2016A, due 2031	—	—	58
3.000% Gas and Water Series 2016B, due 2036(3)	60	62	62
1.850% Water Facilities Series 2016C, due 2036(4)	—	—	30
2.050% Water Facilities Series 2016D, due 2036(2)(5)	25	25	25
2.050% Water Facilities Series 2016E, due 2036(2)(5)	25	25	25
2.050% Water Facilities Series 2016F, due 2036(2)	75	74	—
1.850% Water Facilities Series 2016G, due 2036(2)	20	20	—
Total Sierra Pacific	1,137	1,136	1,121
Total NV Energy	$ 3,836	$ 3,821	$ 3,817

(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 April 2022 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.

(4) Bond was purchased by Sierra Pacific during 2019. As of December 31, 2018 the bond variable interest rate was 1.750% to 1.820%.

(5) Bonds were purchased by Sierra Pacific during 2019 and re-offered at a fixed interest rate. As of December 31, 2018 the bonds variable interest rate was 1.750% to 1.820%.

In January 2020, Nevada Power issued $425 million of its 2.400% General and Refunding Mortgage Notes, Series DD, due May 2030 and issued $300 million of its 3.125% General and Refunding Mortgage Notes, Series EE, due August 2050. Nevada Power intends to use the net proceeds from the sale of the Notes to repay $575 million aggregate principal amount of its 2.750% General and Refunding Mortgage Notes, Series BB, maturing in April 2020 and for general corporate purposes.

In January 2020, Nevada Power issued a 30-day notice of early redemption to repay $575 million of its 2.750% General and Refunding Mortgage Notes, Series BB.

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, 2019, approximately $8.7 billion of Nevada Power's and $4.2 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)	2019	2018
8.875% Bonds, due 2020	$ 133	$ 135	$ 133
9.25% Bonds, due 2020	265	265	260
4.133% to 4.586% European Investment Bank loans, due 2019 to 2022	251	252	293
7.25% Bonds, due 2022	265	270	262
2.50% Bonds, due 2025	199	197	189
2.073% European Investment Bank loan, due 2025	66	68	65
2.564% European Investment Bank loans, due 2027	332	330	318
7.25% Bonds, due 2028	246	250	241
4.375% Bonds, due 2032	199	196	188
5.125% Bonds, due 2035	265	262	252
5.125% Bonds, due 2035	199	197	189
2.750% Bonds, due 2049	199	196	—
2.250% Bonds, due 2059	398	389	—
Variable-rate bond, due 2026(2)	217	214	236
Total Northern Powergrid	$ 3,234	$ 3,221	$ 2,626

(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 86% of the outstanding debt. The variable interest rate as of December 31, 2019 was 2.54% 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	2019	2018
Northern Natural Gas:			
4.25% Senior Notes, due 2021	$ 200	$ 200	$ 199
5.80% Senior Bonds, due 2037	150	149	149
4.10% Senior Bonds, due 2042	250	248	248
4.30% Senior Bonds, due 2049	650	650	446
Total BHE Pipeline Group	$ 1,250	$ 1,247	$ 1,042

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)]	2019	2018
AltaLink Investments, L.P.:			
Series 12-1 Senior Bonds, 3.674%, due 2019	$ —	$ —	$ 148
Series 13-1 Senior Bonds, 3.265%, due 2020	154	154	148
Series 15-1 Senior Bonds, 2.244%, due 2022	154	154	146
Total AltaLink Investments, L.P.	308	308	442
AltaLink, L.P.:			
Series 2013-2 Notes, 3.621%, due 2020	96	96	92
Series 2012-2 Notes, 2.978%, due 2022	212	212	201
Series 2013-4 Notes, 3.668%, due 2023	385	384	366
Series 2014-1 Notes, 3.399%, due 2024	269	269	256
Series 2016-1 Notes, 2.747%, due 2026	269	269	255
Series 2006-1 Notes, 5.249%, due 2036	115	115	109
Series 2010-1 Notes, 5.381%, due 2040	96	96	91
Series 2010-2 Notes, 4.872%, due 2040	115	115	109
Series 2011-1 Notes, 4.462%, due 2041	212	211	201
Series 2012-1 Notes, 3.990%, due 2042	404	398	380
Series 2013-3 Notes, 4.922%, due 2043	269	268	256
Series 2014-3 Notes, 4.054%, due 2044	227	226	215
Series 2015-1 Notes, 4.090%, due 2045	269	268	255
Series 2016-2 Notes, 3.717%, due 2046	346	345	328
Series 2013-1 Notes, 4.446%, due 2053	192	192	183
Series 2014-2 Notes, 4.274%, due 2064	100	100	95
Total AltaLink, L.P.	3,576	3,564	3,392
Other:			
Construction Loan, 5.620%, due 2020	7	7	8
Total BHE Transmission	$ 3,891	$ 3,879	$ 3,842

(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	2019	2018
Fixed-rate[1]:			
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	$ 78	$ 77	$ 84
Solar Star Funding Senior Notes, 3.950%, due 2035	283	280	292
Solar Star Funding Senior Notes, 5.375%, due 2035	894	886	915
Grande Prairie Wind Senior Notes, 3.860%, due 2037	358	355	392
Topaz Solar Farms Senior Notes, 5.750%, due 2039	680	672	709
Topaz Solar Farms Senior Notes, 4.875%, due 2039	195	193	205
Alamo 6 Senior Notes, 4.170%, due 2042	216	213	221
Other	13	13	16
Variable-rate[1]:			
Pinyon Pines I and II Term Loans, due 2020[2]	284	284	310
TX Jumbo Road Term Loan, due 2025[2]	161	158	176
Marshall Wind Term Loan, due 2026[2]	77	75	81
Total BHE Renewables	$ 3,239	$ 3,206	$ 3,401

(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 through December 31, 2019 and 50% of the Pinyon Pines outstanding debt thereafter, and 100% of the TX Jumbo Road and Marshall Wind outstanding debt. The variable interest rate as of December 31, 2019 and 2018 was 3.69% and 4.55%, respectively, while the fixed interest rates as of December 31, 2019 and 2018 ranged from 3.21% to 5.41%.

In January 2020, Pinyon Pines I and II repaid $284 million of its variable-rate term loans. This debt was refinanced with $382 million of fifteen year variable-rate term loans due December 2034. The new term loans amortize semiannually and 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 100% of the new term loans.

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	2019	2018
Variable-rate:			
Variable-rate term loan (2019 - 3.299%, 2018 - 4.022%), due 2022[1]	$ 213	$ 213	$ 233

(1) Term loan amortizes quarterly and variable-rate resets monthly.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2020 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
BHE senior notes	$ 350	$ 450	$ —	$ 900	$ —	$ 6,951	$ 8,651
BHE junior subordinated debentures	—	—	—	—	—	100	100
PacifiCorp	38	420	605	449	591	5,602	7,705
MidAmerican Funding	—	—	—	315	535	6,665	7,515
NV Energy	890	—	—	250	—	2,696	3,836
Northern Powergrid	480	32	498	34	35	2,155	3,234
BHE Pipeline Group	—	200	—	—	—	1,050	1,250
BHE Transmission	251	1	366	386	270	2,617	3,891
BHE Renewables	503	172	170	174	184	2,036	3,239
HomeServices	27	33	153	—	—	—	213
Totals	$ 2,539	$ 1,308	$ 1,792	$ 2,508	$ 1,615	$ 29,872	$ 39,634

(12) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacted 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, in December 2017, 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 in 2017 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 recorded the impacts of the 2017 Tax Reform in December 2017 and believed 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 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 believed the estimates for the repatriation tax to be reasonable, however, additional time was required to validate the inputs to the foreign earnings and profits calculation, the basis on which the repatriation tax is determined and additional guidance was required to determine state income tax implications. The Company also believed its interpretations for bonus depreciation to be reasonable, however, clarifying guidance was needed. During 2018, the Company finalized its provisional amounts resulting in a $134 million reduction to the repatriation tax liability estimate, based on further analysis of the earnings and profits completed during 2018 and additional guidance from certain states. In addition, the Company recorded a current tax benefit and deferred tax expense of $68 million following clarifying bonus depreciation guidance. As a result of 2017 Tax Reform and the nature of the Company's regulated businesses, the Company reduced the associated deferred income tax liabilities $27 million and increased regulatory liabilities by the same amount.

Iowa Senate File 2417

In May 2018, Iowa Senate File 2417 was signed into law, which, among other items, reduces the state of Iowa corporate tax rate from 12% to 9.8% and eliminates corporate federal deductibility, both for tax years starting in 2021. 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 Iowa Senate File 2417, the Company reduced deferred income tax liabilities $61 million and decreased deferred income tax expense by $2 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 $59 million. In connection with Iowa Senate File 2417, the Company determined it was more appropriate to present the deferred income tax assets of $609 million associated with the state of Iowa net operating loss carryforward as a long-term income tax receivable from Berkshire Hathaway as a component of BHE's shareholders' equity. As the Company does not currently expect to receive the majority of the income tax amounts from Berkshire Hathaway related to the state of Iowa prior to the 2021 effective date, the Company remeasured the long-term income tax receivable with Berkshire Hathaway at the enactment date and recorded a decrease to the long-term income tax receivable from Berkshire Hathaway of $115 million. Subsequent to the remeasurement date, the Company amended the tax sharing agreement with Berkshire Hathaway and received $90 million in 2019 related to previously used state of Iowa net operating loss carryforwards.

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

	2019	2018	2017
Current:			
Federal	$ (956)	$ (686)	$ (653)
State	(13)	(9)	(3)
Foreign	81	104	83
	(888)	(591)	(573)
Deferred:			
Federal	431	165	(76)
State	(127)	(131)	100
Foreign	(8)	(20)	2
	296	14	26
Investment tax credits	(6)	(6)	(7)
Total	$ (598)	$ (583)	$ (554)

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:

	2019	2018	2017
Federal statutory income tax rate	21 %	21 %	35 %
Income tax credits	(32)	(30)	(20)
Effects of ratemaking	(6)	(8)	(1)
State income tax, net of federal income tax benefit	(5)	(6)	3
Effects of tax rate change and repatriation tax	—	(4)	(31)
Income tax effect of foreign income	(2)	(3)	(5)
Equity income	—	1	(2)
Other, net	(1)	(1)	(1)
Effective income tax rate	(25)%	(30)%	(22)%

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 ("PTC") from wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp and BHE Renewables. Federal renewable electricity PTCs 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 Company's provision for income taxes has been computed on a stand-alone basis. Berkshire Hathaway includes the Company in its consolidated United States federal and Iowa state income tax returns and the majority of the Company's United States federal income tax is remitted to or received from Berkshire Hathaway. As of December 31, 2019, the Company had a current income tax payable to Berkshire Hathaway for federal income tax of $76 million and a long-term income tax receivable from Berkshire Hathaway, reflected as a component of BHE's shareholders' equity, of $530 million for Iowa state income tax. As of December 31, 2018, the Company had a current income tax payable to Berkshire Hathaway for federal income tax of $172 million, a current income tax receivable from Berkshire Hathaway for Iowa state income tax of $90 million and a long-term income tax receivable from Berkshire Hathaway, reflected as a component of BHE's shareholders' equity, of $457 million for Iowa state income tax. Additionally, for the years ended December 31, 2019 and 2018 the Company generated $79 million and $53 million, respectively, of state of Iowa net operating losses which were carried forward and increased the long-term income tax receivable from Berkshire Hathaway.

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

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 1,610	$ 1,674
Federal, state and foreign carryforwards	575	596
AROs	306	232
Other	590	527
Total deferred income tax assets	3,081	3,029
Valuation allowances	(143)	(137)
Total deferred income tax assets, net	2,938	2,892
Deferred income tax liabilities:		
Property-related items	(10,439)	(10,185)
Investments	(1,137)	(876)
Regulatory assets	(631)	(656)
Other	(384)	(222)
Total deferred income tax liabilities	(12,591)	(11,939)
Net deferred income tax liability	$ (9,653)	$ (9,047)

The following table provides the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2019 (in millions):

	Federal	State	Foreign	Total
Net operating loss carryforwards[(1)]	$ 292	$ 5,819	$ 523	$ 6,634
Deferred income taxes on net operating loss carryforwards	61	323	141	525
Expiration dates	2020 - indefinite	2020 - 2039	2035 - 2038	
Tax credits	$ 23	$ 27	$ —	$ 50
Expiration dates	2023 - indefinite	2020 - 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 2020.

The United States Internal Revenue Service has closed its examination of the Company's income tax returns through December 31, 2011. The statute of limitations for the Company's income tax returns have expired through December 31, 2009, for California, Nebraska, Oregon and Utah, through December 31, 2011 for Minnesota and Montana, and through December 31, 2015, except for the impact of any federal audit adjustments, for Idaho, Illinois, Iowa and Kansas. 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 statute of limitations 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):

	2019	2018
Beginning balance	$ 185	$ 181
Additions based on tax positions related to the current year	3	4
Additions for tax positions of prior years	13	38
Reductions for tax positions of prior years	(37)	(38)
Statute of limitations	(9)	2
Settlements	(5)	(2)
Interest and penalties	(5)	—
Ending balance	$ 145	$ 185

As of December 31, 2019 and 2018, the Company had unrecognized tax benefits totaling $139 million and $154 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.

(13) 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 generally 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		
	2019	2018	2017	2019	2018	2017
Service cost	$ 16	$ 21	$ 24	$ 8	$ 9	$ 9
Interest cost	111	105	116	27	24	29
Expected return on plan assets	(154)	(164)	(160)	(40)	(41)	(40)
Settlement	—	21	—	—	—	—
Net amortization	31	28	25	(6)	(13)	(14)
Net periodic benefit cost (credit)	$ 4	$ 11	$ 5	$ (11)	$ (21)	$ (16)

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	
	2019	2018	2019	2018
Plan assets at fair value, beginning of year	$ 2,396	$ 2,761	$ 664	$ 736
Employer contributions	12	38	2	8
Participant contributions	—	—	9	8
Actual return on plan assets	456	(147)	122	(38)
Settlement	(22)	(119)	—	—
Benefits paid	(186)	(137)	(55)	(50)
Plan assets at fair value, end of year	$ 2,656	$ 2,396	$ 742	$ 664

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

	Pension		Other Postretirement	
	2019	2018	2019	2018
Benefit obligation, beginning of year	$ 2,718	$ 3,006	$ 672	$ 721
Service cost	16	21	8	9
Interest cost	111	105	27	24
Participant contributions	—	—	9	8
Actuarial loss (gain)	242	(160)	12	(40)
Amendment	(1)	2	—	—
Settlement	(22)	(119)	—	—
Benefits paid	(186)	(137)	(55)	(50)
Benefit obligation, end of year	$ 2,878	$ 2,718	$ 673	$ 672
Accumulated benefit obligation, end of year	$ 2,867	$ 2,709		

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	
	2019	2018	2019	2018
Plan assets at fair value, end of year	$ 2,656	$ 2,396	$ 742	$ 664
Benefit obligation, end of year	2,878	2,718	673	672
Funded status	$ (222)	$ (322)	$ 69	$ (8)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 73	$ 20	$ 76	$ 5
Other current liabilities	(13)	(13)	—	—
Other long-term liabilities	(282)	(329)	(7)	(13)
Amounts recognized	$ (222)	$ (322)	$ 69	$ (8)

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 $252 million and $256 million as of December 31, 2019 and 2018, 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	
	2019	2018	2019	2018
Fair value of plan assets	$ 1,939	$ 1,752	$ 439	$ 417
Projected benefit obligation	$ 2,227	$ 2,091	$ 446	$ 429
Accumulated benefit obligation	$ 2,222	$ 2,085		

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	
	2019	2018	2019	2018
Net loss	$ 653	$ 747	$ (23)	$ 50
Prior service credit	(2)	—	(14)	(22)
Regulatory deferrals	1	(1)	6	7
Total	$ 652	$ 746	$ (31)	$ 35

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2019 and 2018 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2017	$ 665	$ (43)	$ 20	$ 642
Net loss (gain) arising during the year	114	43	(6)	151
Net prior service cost arising during the year	—	—	2	2
Settlement	(21)	—	—	(21)
Net amortization	(28)	—	—	(28)
Total	65	43	(4)	104
Balance, December 31, 2018	730	—	16	746
Net (gain) loss arising during the year	(38)	(33)	10	(61)
Net prior service credit arising during the year	—	—	(2)	(2)
Net amortization	(31)	—	—	(31)
Total	(69)	(33)	8	(94)
Balance, December 31, 2019	$ 661	$ (33)	$ 24	$ 652

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Other Postretirement				
Balance, December 31, 2017	$ 10	$ (26)	$ —	$ (16)
Net loss arising during the year	23	14	1	38
Net amortization	11	2	—	13
Total	34	16	1	51
Balance, December 31, 2018	44	(10)	1	35
Net gain arising during the year	(45)	(23)	(4)	(72)
Net amortization	5	1	—	6
Total	(40)	(22)	(4)	(66)
Balance, December 31, 2019	$ 4	$ (32)	$ (3)	$ (31)

Plan Assumptions

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

	Pension			Other Postretirement		
	2019	2018	2017	2019	2018	2017
Benefit obligations as of December 31:						
Discount rate	3.32%	4.25%	3.60%	3.24%	4.21%	3.57%
Rate of compensation increase	2.75%	2.75%	2.75%	NA	NA	NA
Interest crediting rates for cash balance plan						
2017	NA	NA	2.49%	NA	NA	NA
2018	NA	3.38%	3.06%	NA	NA	NA
2019	3.22%	3.54%	3.06%	NA	NA	NA
2020	2.94%	3.54%	2.72%	NA	NA	NA
2021	2.94%	3.56%	2.72%	NA	NA	NA
2022	3.02%	3.56%	2.72%	NA	NA	NA
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.25%	3.60%	4.06%	4.21%	3.57%	4.01%
Expected return on plan assets	6.48%	6.36%	6.55%	6.39%	6.44%	6.73%
Rate of compensation increase	2.75%	2.75%	2.75%	NA	NA	NA
Interest crediting rate for cash balance plan	3.22%	3.38%	2.49%	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.

	2019	2018
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.50%	6.80%
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

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $13 million and $- million, respectively, during 2020. 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 evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plans.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2020 through 2024 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2020	$ 233	$ 57
2021	218	56
2022	213	55
2023	212	54
2024	205	51
2025-2029	927	224

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, 2019:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities(1)	30-43	33-37
Equity securities(1)	48-65	62-66
Limited partnership interests	6-12	1-3
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	Total
As of December 31, 2019:			
Cash equivalents	$ 27	$ 36	$ 63
Debt securities:			
United States government obligations	210	—	210
International government obligations	—	5	5
Corporate obligations	—	376	376
Municipal obligations	—	28	28
Agency, asset and mortgage-backed obligations	—	115	115
Equity securities:			
United States companies	547	1	548
International companies	136	—	136
Investment funds[2]	125	—	125
Total assets in the fair value hierarchy	$ 1,045	$ 561	1,606
Investment funds[2] measured at net asset value			915
Limited partnership interests[3] measured at net asset value			93
Real estate funds measured at net asset value			42
Total assets measured at fair value			$ 2,656
As of December 31, 2018:			
Cash equivalents	$ 8	$ 41	$ 49
Debt securities:			
United States government obligations	160	—	160
International government obligations	—	5	5
Corporate obligations	—	373	373
Municipal obligations	—	29	29
Agency, asset and mortgage-backed obligations	—	123	123
Equity securities:			
United States companies	492	1	493
International companies	108	—	108
Investment funds[2]	119	—	119
Total assets in the fair value hierarchy	$ 887	$ 572	1,459
Investment funds[2] measured at net asset value			792
Limited partnership interests[3] measured at net asset value			104
Real estate funds measured at net asset value			41
Total assets measured at fair value			$ 2,396

(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 2019 and 59% and 41%, respectively, for 2018. Additionally, these funds are invested in United States and international securities of approximately 66% and 34%, respectively, for 2019 and 73% and 27%, respectively, for 2018.

(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	Total
As of December 31, 2019:			
Cash equivalents	$ 17	$ 1	$ 18
Debt securities:			
United States government obligations	23	—	23
Corporate obligations	—	44	44
Municipal obligations	—	57	57
Agency, asset and mortgage-backed obligations	—	33	33
Equity securities:			
United States companies	151	—	151
International companies	6	—	6
Investment funds	236	—	236
Total assets in the fair value hierarchy	$ 433	$ 135	568
Investment funds measured at net asset value			169
Limited partnership interests measured at net asset value			5
Total assets measured at fair value			$ 742
As of December 31, 2018:			
Cash equivalents	$ 10	$ 2	$ 12
Debt securities:			
United States government obligations	13	—	13
Corporate obligations	—	42	42
Municipal obligations	—	45	45
Agency, asset and mortgage-backed obligations	—	30	30
Equity securities:			
United States companies	158	—	158
International companies	6	—	6
Investment funds[(2)]	202	1	203
Total assets in the fair value hierarchy	$ 389	$ 120	509
Investment funds[(2)] measured at net asset value			149
Limited partnership interests[(3)] measured at net asset value			6
Total assets measured at fair value			$ 664

(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 58% and 42%, respectively, for 2019 and 65% and 35%, respectively, for 2018. Additionally, these funds are invested in United States and international securities of approximately 75% and 25%, respectively, for 2019 and 79% and 21%, respectively, for 2018.

(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 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):

	2019	2018	2017
Service cost	$ 16	$ 19	$ 23
Interest cost	49	56	58
Expected return on plan assets	(100)	(101)	(100)
Settlement	26	44	31
Net amortization	46	45	63
Net periodic benefit cost	$ 37	$ 63	$ 75

Funded Status

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

	2019	2018
Plan assets at fair value, beginning of year	$ 1,989	$ 2,368
Employer contributions	56	60
Participant contributions	1	1
Actual return on plan assets	194	(44)
Settlement	(99)	(205)
Benefits paid	(71)	(71)
Foreign currency exchange rate changes	81	(120)
Plan assets at fair value, end of year	$ 2,151	$ 1,989

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

	2019	2018
Benefit obligation, beginning of year	$ 1,833	$ 2,201
Service cost	16	19
Interest cost	49	56
Participant contributions	1	1
Actuarial loss (gain)	175	(87)
Settlement	(99)	(182)
Amendment	—	8
Benefits paid	(71)	(71)
Foreign currency exchange rate changes	115	(112)
Benefit obligation, end of year	$ 2,019	$ 1,833
Accumulated benefit obligation, end of year	$ 1,786	$ 1,637

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):

	2019	2018
Plan assets at fair value, end of year	$ 2,151	$ 1,989
Benefit obligation, end of year	2,019	1,833
Funded status	$ 132	$ 156
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 132	$ 156

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):

	2019	2018
Net loss	$ 543	$ 472
Prior service cost	6	8
Total	$ 549	$ 480

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):

	2019	2018
Balance, beginning of year	$ 480	$ 510
Net loss arising during the year	81	59
Net prior service cost arising during the year	—	8
Settlement	(26)	(22)
Net amortization	(46)	(45)
Foreign currency exchange rate changes	60	(30)
Total	69	(30)
Balance, end of year	$ 549	$ 480

Plan Assumptions

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

	2019	2018	2017
Benefit obligations as of December 31:			
Discount rate	2.10%	2.90%	2.60%
Rate of compensation increase	3.30%	3.55%	3.45%
Rate of future price inflation	2.80%	3.05%	2.95%
Net periodic benefit cost for the years ended December 31:			
Discount rate	2.90%	2.60%	2.70%
Expected return on plan assets	5.10%	4.90%	5.00%
Rate of compensation increase	3.55%	3.45%	3.00%
Rate of future price inflation	3.05%	2.95%	3.00%

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £43 million during 2020. The expected benefit payments to participants in the UK Plan for 2020 through 2024 and for the five years thereafter excluding lump sum settlement elections, using the foreign currency exchange rate as of December 31, 2019, are summarized below (in millions):

2020	$ 74
2021	75
2022	77
2023	79
2024	81
2025-2029	436

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, 2019:

	%
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, 2019:				
Cash equivalents	$ 3	$ 24	$ —	$ 27
Debt securities:				
United Kingdom government obligations	960	—	—	960
Equity securities:				
Investment funds(2)	—	818	—	818
Real estate funds	—	—	243	243
Total	$ 963	$ 842	$ 243	2,048
Investment funds(2) measured at net asset value				103
Total assets measured at fair value				$ 2,151
As of December 31, 2018:				
Cash equivalents	$ 3	$ 59	$ —	$ 62
Debt securities:				
United Kingdom government obligations	891	—	—	891
Equity securities:				
Investment funds(2)	—	697	—	697
Real estate funds	—	—	239	239
Total	$ 894	$ 756	$ 239	1,889
Investment funds(2) measured at net asset value				100
Total assets measured at fair value				$ 1,989

(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 38% and 62%, respectively, for 2019 and 36% and 64%, respectively, for 2018.

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		
	2019	2018	2017
Beginning balance	$ 239	$ 230	$ 105
Actual return on plan assets still held at period end	(5)	23	6
Purchases	—	—	104
Foreign currency exchange rate changes	9	(14)	15
Ending balance	$ 243	$ 239	$ 230

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 $115 million, $112 million and $103 million for the years ended December 31, 2019, 2018 and 2017, respectively.

(14) 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 $2.4 billion as of December 31, 2019 and 2018.

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

	2019	2018
Fossil fuel facilities	$ 623	$ 371
Quad Cities Station	358	345
Wind generating facilities	211	174
Offshore pipeline facilities	15	33
Solar generating facilities	21	20
Other	44	42
Total asset retirement obligations	$ 1,272	$ 985
Quad Cities Station nuclear decommissioning trust funds	$ 599	$ 504

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

	2019	2018
Beginning balance	$ 985	$ 954
Change in estimated costs	257	10
Additions	43	28
Retirements	(61)	(45)
Accretion	48	38
Ending balance	$ 1,272	$ 985
Reflected as:		
Other current liabilities	$ 167	$ 43
Other long-term liabilities	1,105	942
Total ARO liability	$ 1,272	$ 985

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.

In January 2018, MidAmerican Energy completed groundwater testing at its coal combustion residuals ("CCR") surface impoundments. Based on this information, MidAmerican Energy discontinued sending CCR to surface impoundments effective April 2018 and initiated analysis of additional actions to be taken. As a result of that analysis, MidAmerican Energy will remove all CCR material located below the water table and cap the material in such facilities, which is a more extensive closure activity than previously assumed. In the first quarter of 2019, MidAmerican Energy increased the asset retirement obligations for its fossil-fueled generating facilities by $237 million related to the cost of this closure activity. Closure activity on the six existing surface impoundments is estimated to extend through 2023.

(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, 2019:					
Assets:					
Commodity derivatives	$ —	$ 45	$ 108	$ (24)	$ 129
Interest rate derivatives	—	2	14	—	16
Mortgage loans held for sale	—	1,039	—	—	1,039
Money market mutual funds[(2)]	824	—	—	—	824
Debt securities:					
United States government obligations	189	—	—	—	189
International government obligations	—	4	—	—	4
Corporate obligations	—	58	—	—	58
Municipal obligations	—	1	—	—	1
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
United States companies	336	—	—	—	336
International companies	1,131	—	—	—	1,131
Investment funds	169	—	—	—	169
	$ 2,649	$ 1,150	$ 122	$ (24)	$ 3,897
Liabilities:					
Commodity derivatives	$ (4)	$ (143)	$ (11)	$ 103	$ (55)
Interest rate derivatives	(2)	(19)	—	—	(21)
	$ (6)	$ (162)	$ (11)	$ 103	$ (76)
As of December 31, 2018:					
Assets:					
Commodity derivatives	$ 1	$ 91	$ 108	$ (52)	$ 148
Interest rate derivatives	1	13	10	—	24
Mortgage loans held for sale	—	468	—	—	468
Money market mutual funds[(2)]	409	—	—	—	409
Debt securities:					
United States government obligations	187	—	—	—	187
International government obligations	—	4	—	—	4
Corporate obligations	—	46	—	—	46
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
United States companies	256	—	—	—	256
International companies	1,441	—	—	—	1,441
Investment funds	128	—	—	—	128
	$ 2,423	$ 625	$ 118	$ (52)	$ 3,114
Liabilities:					
Commodity derivatives	$ (1)	$ (180)	$ (9)	$ 111	$ (79)
Interest rate derivatives	—	(32)	—	—	(32)
	$ (1)	$ (212)	$ (9)	$ 111	$ (111)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $79 million and $59 million as of December 31, 2019 and 2018, 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.

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. 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		
	2019	2018	2017	2019	2018	2017
Beginning balance	$ 99	$ 94	$ 60	$ 10	$ 9	$ 6
Changes included in earnings	10	1	23	479	181	147
Changes in fair value recognized in OCI	(1)	2	(3)	—	—	—
Changes in fair value recognized in net regulatory assets	(26)	3	(1)	—	—	—
Purchases	6	3	1	—	—	4
Settlements	9	(4)	14	(475)	(180)	(148)
Ending balance	$ 97	$ 99	$ 94	$ 14	$ 10	$ 9

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):

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 39,353	$ 46,004	$ 36,774	$ 39,398

(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, 2019 are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 2,218	$ 1,527	$ 1,193	$ 1,093	$ 1,088	$ 13,584	$ 20,703
Construction commitments	1,682	521	27	2	8	—	2,240
Easements	62	68	70	72	70	2,259	2,601
Maintenance, service and other contracts	669	342	324	300	255	1,624	3,514
	$ 4,631	$ 2,458	$ 1,614	$ 1,467	$ 1,421	$ 17,467	$ 29,058

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, 2019, 2018 and 2017, $123 million, $111 million and $109 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:

- PacifiCorp's costs associated with certain generating plant, transmission and distribution projects.
- MidAmerican Energy's firm construction commitments primarily consisting of contracts for the construction and repowering of wind-powered generating facilities in 2020 and 2021.
- AltaLink's investments in directly assigned transmission projects from the AESO.

Easements

The Company has non-cancelable easements for land on which certain of its assets, primarily wind-powered generating facilities, are located.

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.

BHE Renewables' Counterparty Risk

On January 29, 2019, PG&E Corporation and Pacific Gas and Electric Company (the "PG&E Utility") (together "PG&E") filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of California ("PG&E Bankruptcy Filing"). The Company owns 100% of Topaz and owns a 49% interest in Agua Caliente. Topaz is a 550-MW solar photovoltaic electric power generating facility located in California. Topaz sells 100% of its energy, capacity and renewable energy credits generated from the facility to PG&E Utility under a 25-year wholesale power purchase agreement ("PPA") that is in effect until October 2039. As of December 31, 2019, the Company's consolidated balance sheet includes $1.0 billion of property, plant and equipment, net and $0.9 billion of non-recourse project debt related to Topaz. Agua Caliente is a 290-MW solar photovoltaic electric power generating facility located in Arizona. Agua Caliente sells 100% of its energy, capacity and renewable energy credits generated from the facility to PG&E Utility under a 25-year wholesale PPA that is in effect until June 2039. As of December 31, 2019, the Company's equity investment in Agua Caliente totals $73 million and the project has $0.8 billion of non-recourse project debt owed to the United States Department of Energy. The PG&E Bankruptcy Filing is an event of default under the Topaz PPA ("PPA Default"). PG&E paid in full the invoices for December 2018 deliveries and all amounts invoiced to date for post-petition energy deliveries for both Topaz and Agua Caliente. PG&E has not paid for the power delivered from January 1 through January 28, 2019. The Company continues to perform on its obligations and deliver renewable energy to the PG&E Utility, and PG&E has publicly stated it will pay suppliers in full under normal terms for post-petition goods and services received. The Company maintains that, in light of the current facts and circumstances, the PPA Default could not reasonably be expected to result in a material adverse effect under the Topaz indenture and, therefore, no default has occurred under the Topaz indenture. In July 2019, the California Governor signed AB 1054 into law. AB 1054 is comprehensive legislation addressing wildfire risk in the state of California that, among other items, authorizes a wildfire fund which would operate as an insurance fund to support the creditworthiness of electrical utilities, if certain utilities, including PG&E, participate by making the required contributions, among other things. In July 2019, PG&E notified the CPUC of its intent to participate in the insurance fund and such participation requires, among other items, PG&E to exit bankruptcy by June 30, 2020. The Company believes it is more likely than not that no impairment exists and current debt obligations will be met, as post-petition contractual revenue payments are expected to be paid by PG&E Utility to the Topaz and Agua Caliente projects. The Company will continue to monitor the situation, including continued receipt of future PG&E payments and the future risk of the PPAs being rejected or modified through the bankruptcy process.

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 climate change, renewable portfolio standards, air and water quality, emissions performance standards, 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 is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSA"), which is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA does not guarantee dam removal. Instead, it establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can occur consistent with the settlement's terms. For PacifiCorp, the key elements of the settlement include: (1) a contribution from PacifiCorp's Oregon and California customers capped at $200 million plus $250 million in California bond funds; (2) complete indemnification from harms associated with dam removal; (3) transfer of the Federal Energy Regulatory Commission ("FERC") license to a third-party dam removal entity, the Klamath River Renewal Corporation ("KRRC"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

In September 2016, the KRRC and PacifiCorp filed a joint application with the FERC to transfer the license for the four mainstem Klamath dams from PacifiCorp to the KRRC. Over the past two years, the KRRC has been supplementing the application with additional information about its financial, technical, and legal capacity to become the licensee. In July 2019, the KRRC provided the FERC with additional information about its financial capacity to become a licensee, including updated cost estimates, and its insurance, bonding and liability transfer package. The FERC is evaluating the KRRC's information and the proposed license transfer. The KRRC will continue to refine its insurance, bonding and liability transfer package, and PacifiCorp will review the KRRC's capacity to fulfill its indemnity obligation under the KHSA. If certain conditions in the amended KHSA are not satisfied (e.g., inadequate funding or inability of KRRC to satisfy its indemnification obligation) and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

The United States Court of Appeals for the District of Columbia Circuit issued a decision in the *Hoopa Valley Tribe v. FERC* litigation, in January 2019, finding that the states of California and Oregon have waived their Clean Water Act, Section 401, water quality certification authority over the Klamath hydroelectric project relicensing. This decision has the potential to limit the ability of the States to impose water quality conditions on new and relicensed projects. Environmental interests, supported by California, Oregon and other states, asked the court to rehear the case, which was denied. Subsequently, environmental groups, supported by numerous states, filed a petition for certiorari before the United States Supreme Court, which was denied on December 9, 2019, thereby allowing the circuit court opinion to stand as a final and unappealable decision.

As of December 31, 2019, PacifiCorp's assets included $29 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 in Utah, Wyoming and Idaho through December 31, 2022.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $168 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) Revenue from Contracts with Customers

The Company uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The following table summarizes the Company's energy products and services revenue by regulated energy and nonregulated energy, with further disaggregation of regulated energy by customer class and line of business, including a reconciliation to the Company's reportable segment information included in Note 22 (in millions):

	For the Year Ended December 31, 2019								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,789	$ 1,938	$ 2,740	$ —	$ —	$ —	$ —	$ (2)	$ 9,465
Retail Gas	—	570	116	—	—	—	—	—	686
Wholesale	99	309	51	—	—	—	—	(2)	457
Transmission and distribution	98	57	98	876	—	690	—	—	1,819
Interstate pipeline	—	—	—	—	1,122	—	—	(118)	1,004
Other	—	—	2	—	—	—	—	—	2
Total Regulated	4,986	2,874	3,007	876	1,122	690	—	(122)	13,433
Nonregulated	—	30	—	36	—	17	744	577	1,404
Total Customer Revenue	4,986	2,904	3,007	912	1,122	707	744	455	14,837
Other revenue	82	23	30	101	9	—	188	101	534
Total	$ 5,068	$ 2,927	$ 3,037	$ 1,013	$ 1,131	$ 707	$ 932	$ 556	$ 15,371

	For the Year Ended December 31, 2018								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,732	$ 1,915	$ 2,773	$ —	$ —	$ —	$ —	$ (1)	$ 9,419
Retail Gas	—	636	101	—	—	—	—	—	737
Wholesale	55	411	39	—	—	—	—	(4)	501
Transmission and distribution	103	56	96	892	—	700	—	(1)	1,846
Interstate pipeline	—	—	—	—	1,232	—	—	(125)	1,107
Other	—	—	2	—	—	—	—	—	2
Total Regulated	4,890	3,018	3,011	892	1,232	700	—	(131)	13,612
Nonregulated	—	14	—	39	—	10	673	624	1,360
Total Customer Revenue	4,890	3,032	3,011	931	1,232	710	673	493	14,972
Other revenue(1)	136	21	28	89	(29)	—	235	121	601
Total	$ 5,026	$ 3,053	$ 3,039	$ 1,020	$ 1,203	$ 710	$ 908	$ 614	$ 15,573

(1) Includes net payments to counterparties for the financial settlement of certain derivative contracts at BHE Pipeline Group.

Real Estate Services

The following table summarizes the Company's real estate services revenue by line of business (in millions):

	HomeServices	
	Years Ended December 31,	
	2019	2018
Customer Revenue:		
Brokerage	$ 4,028	$ 3,882
Franchise	68	67
Total Customer Revenue	4,096	3,949
Other revenue	377	265
Total	$ 4,473	$ 4,214

Remaining Performance Obligations

The following table summarizes the Company's revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2019, by reportable segment (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
BHE Pipeline Group	$ 871	$ 5,136	$ 6,007

(18) 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 to BHE at the then-current fair value dependent on certain circumstances controlled by BHE.

For the year ended December 31, 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.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2022 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 $18.1 billion as of December 31, 2019.

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. As a result of these restrictions, BHE's subsidiaries had restricted net assets of $17.5 billion as of December 31, 2019.

(19) 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 Marketable Securities	Unrealized Gains (Losses) on Cash Flow Hedges	AOCI Attributable To BHE Shareholders, Net
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)
Adoption of ASU 2016-01	—	—	(1,085)	—	(1,085)
Other comprehensive income (loss)	25	(494)	—	7	(462)
Balance, December 31, 2018	(358)	(1,623)	—	36	(1,945)
Other comprehensive (loss) income	(59)	327	—	(29)	239
Balance, December 31, 2019	$ (417)	$ (1,296)	$ —	$ 7	$ (1,706)

Reclassifications from AOCI to net income for the years ended December 31, 2019, 2018 and 2017 were insignificant. Additionally, refer to the "Foreign Operations" discussion in Note 13 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(20) Noncontrolling Interests

Included in noncontrolling interests on the Consolidated Balance Sheets are preferred securities of subsidiaries of $58 million as of December 31, 2019 and 2018, 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.

(21) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

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 cash and cash equivalents as of December 31, 2019 and December 31, 2018, consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements and debt service obligations for certain of the Company's nonregulated renewable energy projects. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and December 31, 2018, as presented in the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2019	**2018**
Cash and cash equivalents	$ 1,040	$ 627
Restricted cash and cash equivalents	212	227
Investments and restricted cash and cash equivalents and investments	16	29
Total cash and cash equivalents and restricted cash and cash equivalents	$ 1,268	$ 883

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

	2019	2018	2017
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 1,723	$ 1,713	$ 1,715
Income taxes received, net[1]	$ 850	$ 780	$ 540
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 888	$ 823	$ 653
Common stock exchanged for junior subordinated debentures	$ —	$ —	$ 100

(1) Includes $942 million, $884 million and $636 million of income taxes received from Berkshire Hathaway in 2019, 2018 and 2017, respectively.

(22) Segment Information

The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, BHE Transmission, whose business includes operations in Canada, and BHE Renewables, whose business includes operations in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2019	2018	2017
Operating revenue:			
PacifiCorp	$ 5,068	$ 5,026	$ 5,237
MidAmerican Funding	2,927	3,053	2,846
NV Energy	3,037	3,039	3,015
Northern Powergrid	1,013	1,020	949
BHE Pipeline Group	1,131	1,203	993
BHE Transmission	707	710	699
BHE Renewables	932	908	838
HomeServices	4,473	4,214	3,443
BHE and Other[1]	556	614	594
Total operating revenue	$ 19,844	$ 19,787	$ 18,614
Depreciation and amortization:			
PacifiCorp	$ 954	$ 979	$ 796
MidAmerican Funding	638	609	500
NV Energy	482	456	422
Northern Powergrid	254	250	214
BHE Pipeline Group	115	126	159
BHE Transmission	240	247	239
BHE Renewables	282	268	251
HomeServices	47	51	66
BHE and Other[1]	(1)	(2)	(1)
Total depreciation and amortization	$ 3,011	$ 2,984	$ 2,646
Operating income:			
PacifiCorp	$ 1,072	$ 1,051	$ 1,440
MidAmerican Funding	549	550	544
NV Energy	655	607	766
Northern Powergrid	472	486	488
BHE Pipeline Group	572	525	473
BHE Transmission	323	313	322
BHE Renewables	336	325	316
HomeServices	222	214	214
BHE and Other[1]	(51)	1	(41)
Total operating income	4,150	4,072	4,522
Interest expense	(1,912)	(1,838)	(1,841)
Capitalized interest	77	61	45
Allowance for equity funds	173	104	76
Interest and dividend income	117	113	111
(Losses) gains on marketable securities, net	(288)	(538)	14
Other, net	97	(9)	(420)
Total income before income tax (benefit) expense and equity income (loss)	$ 2,414	$ 1,965	$ 2,507

	Years Ended December 31,		
	2019	2018	2017
Interest expense:			
PacifiCorp	$ 401	$ 384	$ 381
MidAmerican Funding	302	247	237
NV Energy	229	224	233
Northern Powergrid	139	141	133
BHE Pipeline Group	52	43	43
BHE Transmission	157	167	169
BHE Renewables	174	201	204
HomeServices	25	23	7
BHE and Other[1]	433	408	434
Total interest expense	$ 1,912	$ 1,838	$ 1,841
Income tax (benefit) expense:			
PacifiCorp	$ 61	$ 5	$ 362
MidAmerican Funding	(377)	(262)	(202)
NV Energy	98	100	221
Northern Powergrid	59	61	57
BHE Pipeline Group	138	119	170
BHE Transmission	11	7	(124)
BHE Renewables[2]	(325)	(158)	(795)
HomeServices	51	52	49
BHE and Other[1]	(314)	(507)	(292)
Total income tax (benefit) expense	$ (598)	$ (583)	$ (554)
Capital expenditures:			
PacifiCorp	$ 2,175	$ 1,257	$ 769
MidAmerican Funding	2,810	2,332	1,776
NV Energy	657	503	456
Northern Powergrid	602	566	579
BHE Pipeline Group	687	427	286
BHE Transmission	247	270	334
BHE Renewables	122	817	323
HomeServices	54	47	37
BHE and Other	10	22	11
Total capital expenditures	$ 7,364	$ 6,241	$ 4,571

	As of December 31,		
	2019	2018	2017
Property, plant and equipment, net:			
PacifiCorp	$ 20,973	$ 19,570	$ 19,183
MidAmerican Funding	18,377	16,169	14,221
NV Energy	9,613	9,367	9,276
Northern Powergrid	6,606	6,007	6,075
BHE Pipeline Group	5,482	4,904	4,587
BHE Transmission	6,157	5,824	6,330
BHE Renewables	5,976	6,155	5,637
HomeServices	161	141	117
BHE and Other	(40)	(50)	(69)
Total property, plant and equipment, net	$ 73,305	$ 68,087	$ 65,357
Total assets:			
PacifiCorp	$ 24,861	$ 23,478	$ 23,086
MidAmerican Funding	22,664	20,029	18,444
NV Energy	14,128	14,119	13,903
Northern Powergrid	8,385	7,427	7,565
BHE Pipeline Group	6,100	5,511	5,134
BHE Transmission	8,776	8,424	9,009
BHE Renewables	9,961	8,666	7,687
HomeServices	3,846	2,797	2,722
BHE and Other	1,330	1,738	2,658
Total assets	$ 100,051	$ 92,189	$ 90,208

	Years Ended December 31,		
	2019	2018	2017
Operating revenue by country:			
United States	$ 18,108	$ 18,014	$ 16,916
United Kingdom	1,011	1,017	948
Canada	706	710	699
Philippines and other	19	46	51
Total operating revenue by country	$ 19,844	$ 19,787	$ 18,614
Income before income tax (benefit) expense and equity income (loss) by country:			
United States	$ 1,866	$ 1,425	$ 1,927
United Kingdom	326	307	313
Canada	178	155	167
Philippines and other	44	78	100
Total income before income tax (benefit) expense and equity (loss) income by country:	$ 2,414	$ 1,965	$ 2,507

	As of December 31,		
	2019	2018	2017
Property, plant and equipment, net by country:			
United States	$ 60,634	$ 56,362	$ 53,065
United Kingdom	6,504	5,895	5,953
Canada	6,157	5,817	6,323
Philippines and other	10	13	16
Total property, plant and equipment, net by country	$ 73,305	$ 68,087	$ 65,357

(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, 2019 and 2018 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	Home-Services	BHE and Other	Total
December 31, 2017	$ 1,129	$ 2,102	$ 2,369	$ 991	$ 73	$ 1,571	$ 95	$ 1,348	$ —	$9,678
Acquisitions	—	—	—	—	—	—	—	79	—	79
Foreign currency translation	—	—	—	(39)	—	(123)	—	—	—	(162)
December 31, 2018	1,129	2,102	2,369	952	73	1,448	95	1,427	—	9,595
Acquisitions	—	—	—	—	—	—	—	29	—	29
Foreign currency translation	—	—	—	26	—	72	—	—	—	98
December 31, 2019	$ 1,129	$ 2,102	$ 2,369	$ 978	$ 73	$ 1,520	$ 95	$ 1,456	$ —	$9,722

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,				
	2019	2018	2017	2016	2015
Consolidated Statement of Operations Data:					
Operating revenue	$ 5,068	$ 5,026	$ 5,237	$ 5,201	$ 5,232
Operating income[2]	1,072	1,051	1,440	1,428	1,347
Net income	771	738	768	763	695

	As of December 31,				
	2019	2018	2017	2016	2015
Consolidated Balance Sheet Data:					
Total assets	$ 23,697	$ 22,313	$ 21,920	$ 22,394	$ 22,637
Short-term debt	130	30	80	270	20
Current portion of long-term debt obligations[1]	38	350	586	52	66
Long-term debt obligations, excluding current portion[1]	7,620	6,665	6,419	7,000	7,048
Total shareholders' equity	8,437	7,845	7,555	7,390	7,503

(1) On January 1 2019, PacifiCorp adopted Accounting Standards Update No. 2016-02 under a modified retrospective method, which resulted in the reclassification of current capital lease obligation amounts of $2 million at December 31, 2018 and 2017, $6 million at December 31, 2016, and $2 million as of December 31, 2015 to Other current liabilities. The adoption also resulted in the reclassification of the non-current capital lease obligation amounts of $19 million at December 31, 2018, $18 million at December 31, 2017, $21 million at December 31, 2016 and $30 million at December 31, 2015 to Other long-term liabilities.

(2) In January 2018, PacifiCorp retrospectively adopted Accounting Standards Update No. 2017-07, which resulted in the reclassification of amounts other than the service cost for pension and other postretirement benefit plans to Other, net on the Consolidated Statements of Operations of a $22 million benefit for the year ended December 31, 2017, a $2 million cost for the year ended December 31, 2016, and a $7 million cost for the year ended December 31, 2015, with a corresponding increase or reduction to operating expenses.

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, usage trends 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, 2019, was $771 million, an increase of $33 million, or 4%, compared to 2018, primarily due to higher allowances for funds used during construction of $55 million, lower pension and post retirement expense of $11 million primarily due to a prior year pension settlement charge of $22 million, partially offset by higher non-service cost components of pension and other postretirement expenses of $11 million, and higher utility margin of $4 million, partially offset by higher depreciation and amortization expense of $25 million from additional plant placed in-service, excluding a $49 million decrease in accelerated depreciation expense (offset in income tax expense) associated with Oregon's share of certain retired wind equipment in the current year and Utah's share of certain thermal plant units in the prior year, lower PTCs of $21 million from expirations, higher interest expense of $17 million, and higher operations and maintenance expense of $10 million, primarily due to costs associated with the early retirement of Cholla Unit 4 of $24 million, increase in vegetation management costs of $11 million, partially offset by a decrease in expenses primarily due to wildfire suppression costs of $9 million. Utility margin increased primarily due to lower coal-fueled generation volumes, higher retail revenue, and higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms, partially offset by higher purchased electricity costs, and higher natural gas-fueled generation costs. Retail volumes increased 0.4% primarily due to the increase in the average number of residential and commercial customers and the favorable impact of weather on residential customer volumes in all states except Utah, partially offset by lower commercial usage primarily in Utah and Washington. Energy generated decreased 3% for 2019 compared to 2018 primarily due to lower coal-fueled, wind and hydroelectric-powered generation, partially offset by higher natural gas-fueled generation. Wholesale electricity sales volumes decreased 34% and purchased electricity volumes decreased 5%.

Net income for the year ended December 31, 2018, was $738 million, a decrease of $30 million, or 4%, compared to 2017, primarily due to lower utility margin of $198 million, higher depreciation and amortization expense of $183 million, due to accelerated depreciation for Utah's share of certain thermal plant units of $174 million ($170 million offset in income tax expense and $4 million offset in revenue), higher plant in-service, and higher pension and other postretirement expense of $13 million, primarily due to a pension settlement charge, partially offset by a decrease in income tax expense of $355 million and higher allowance for funds used during construction of $22 million. Utility margin decreased due to lower average retail rates, including the impact of the lower federal tax rate due to the 2017 Tax Reform of $152 million, higher natural gas-fueled generation volumes, lower average wholesale prices, higher purchased electricity from higher prices, and lower retail customer volumes, partially offset by higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms, lower natural gas prices, higher wholesale volumes and lower coal-fueled generation volumes. Income tax expense decreased primarily due to lower federal tax rate due to the impact of 2017 Tax Reform, and amortization of a portion of Utah's allocated excess deferred income taxes used to accelerate depreciation of certain thermal plant units as ordered by the UPSC. Retail customer volumes decreased by 0.2% due to impacts of weather on the residential and commercial customer volumes, lower residential usage in all states except Utah and lower industrial usage in Oregon, Washington and Utah, partially offset by an increase in the average number of commercial and residential customers across the service territory, higher commercial and residential usage in Utah, higher irrigation usage, and higher industrial usage in Wyoming and Idaho. Energy generated increased 2% for 2018 compared to 2017 primarily due to higher natural gas-fueled and wind-power generation, partially offset by lower hydroelectric and coal-fueled generation. Wholesale electricity sales volumes increased 15% and purchased electricity volumes decreased 4%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as, utility margin, to help evaluate results of operations. Utility margin is calculated as operating revenue less cost of fuel and energy, which are captions presented on the Consolidated Statements of Operations.

PacifiCorp's cost of fuel and energy is generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in PacifiCorp's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes utility margin more appropriately and concisely explains profitability rather than a discussion of revenue and cost of fuel and energy separately. Management believes the presentation of utility margin provides meaningful and valuable insight into the information management considers important to running the business and a measure of comparability to others in the industry.

Utility margin is not a measure calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2019	2018	Change		2018	2017	Change	
Utility margin:								
Operating revenue	$ 5,068	$ 5,026	$ 42	1%	$ 5,026	$ 5,237	$ (211)	(4)%
Cost of fuel and energy	1,795	1,757	38	2	1,757	1,770	(13)	(1)
Utility margin	3,273	3,269	4	—	3,269	3,467	(198)	(6)
Operations and maintenance	1,048	1,038	10	1	1,038	1,034	4	—
Depreciation and amortization	954	979	(25)	(3)	979	796	183	23
Property and other taxes	199	201	(2)	(1)	201	197	4	2
Operating income	$ 1,072	$ 1,051	$ 21	2%	$ 1,051	$ 1,440	$ (389)	(27)%

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2019	2018	Change		2018	2017	Change	
Utility margin (in millions):								
Operating revenue	$ 5,068	$ 5,026	$ 42	1 %	$ 5,026	$ 5,237	$ (211)	(4)%
Cost of fuel and energy	1,795	1,757	38	2	1,757	1,770	(13)	(1)
Utility margin	$ 3,273	$ 3,269	$ 4	— %	$ 3,269	$ 3,467	$ (198)	(6)%
Sales (GWhs):								
Residential	16,668	16,227	441	3 %	16,227	16,625	(398)	(2)%
Commercial[(1)]	18,151	18,078	73	—	18,078	17,726	352	2
Industrial, irrigation and other[(1)]	20,524	20,810	(286)	(1)	20,810	20,899	(89)	—
Total retail	55,343	55,115	228	—	55,115	55,250	(135)	—
Wholesale	5,480	8,309	(2,829)	(34)	8,309	7,218	1,091	15
Total sales	60,823	63,424	(2,601)	(4)%	63,424	62,468	956	2 %
Average number of retail customers (in thousands)	1,933	1,900	33	2 %	1,900	1,867	33	2 %
Average revenue per MWh:								
Retail	$ 84.80	$ 84.43	$ 0.37	— %	$ 84.43	$ 87.78	$ (3.35)	(4)%
Wholesale	$ 35.21	$ 22.56	$ 12.65	56 %	$ 22.56	$ 28.56	$ (6.00)	(21)%
Sources of energy (GWhs)[(1)]:								
Coal	34,510	36,481	(1,971)	(5)%	36,481	37,362	(881)	(2)%
Natural gas	12,058	10,555	1,503	14	10,555	7,447	3,108	42
Hydroelectric[(2)]	2,842	3,263	(421)	(13)	3,263	4,731	(1,468)	(31)
Wind and other[(2)]	2,385	3,205	(820)	(26)	3,205	2,890	315	11
Total energy generated	51,795	53,504	(1,709)	(3)	53,504	52,430	1,074	2
Energy purchased	12,906	13,579	(673)	(5)	13,579	14,076	(497)	(4)
Total	64,701	67,083	(2,382)	(4)%	67,083	66,506	577	1 %
Average cost of energy per MWh:								
Energy generated[(3)]	$ 19.36	$ 18.91	$ 0.45	2 %	$ 18.91	$ 19.14	$ (0.23)	(1)%
Energy purchased	$ 54.20	$ 48.23	$ 5.97	12 %	$ 48.23	$ 43.25	$ 4.98	12 %

(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 sources may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of RECs or other environmental commodities.

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Utility margin increased $4 million for 2019 compared to 2018 primarily due to:

- $54 million of lower coal-fueled generation costs primarily due to lower average volumes;
- $40 million of higher retail revenue primarily from higher retail customer volumes. Retail volumes increased 0.4% primarily due to an increase in the average number of residential and commercial customers and the favorable impact of weather on residential customer volumes in all states except Utah, partially offset by lower commercial usage primarily in Utah and Washington;
- $11 million of higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms; and
- $5 million of higher wholesale revenue from higher average market prices, offset by lower volumes.

The increases above were partially offset by:

- $45 million of higher purchased electricity costs due to higher average market prices, offset by lower volumes;
- $45 million of higher natural gas-fueled generation costs due to higher average volumes and prices; and
- $11 million of higher wheeling costs and lower wheeling revenues.

Operations and maintenance increased $10 million, or 1%, for 2019 compared to 2018 primarily due to costs associated with the early retirement of Cholla Unit 4 in December 2020 of $24 million and an $11 million increase in vegetation management costs, partially offset by a $9 million decrease in fire suppression costs, a $7 million decrease in materials and supply expense primarily due to usage, and reduced labor and benefits expense primarily due to higher capitalized labor related to construction projects.

Depreciation and amortization decreased $25 million, or 3%, for 2019 compared to 2018 primarily due to a decrease in accelerated depreciation (offset in income tax expense) resulting from $174 million of accelerated depreciation in the prior year for Utah's share of certain thermal plant units pursuant to a 2017 Tax Reform settlement approved by the UPSC compared to $120 million of accelerated depreciation in the current year for Oregon's share of certain retired wind equipment due to repowering as ordered in the Oregon RAC proceeding, partially offset by higher plant-in-service.

Interest expense increased $17 million, or 4%, for 2019 compared to 2018 primarily due to higher average long-term debt balances.

Allowance for borrowed and equity funds increased $55 million, or 104%, for 2019 compared to 2018 primarily due to higher qualified construction work-in-progress balances.

Interest and dividend income increased $6 million, or 40%, for 2019 compared to 2018 primarily due to higher average cash and cash equivalents balances.

Other, net increased $24 million, or 300% for 2019 compared to 2018 primarily due to the prior year pension settlement charge of $22 million and higher cash surrender value of company owned life insurance policies of $5 million, partially offset by higher non-service cost components of pension and other postretirement expense of $11 million.

Income tax expense increased $56 million for 2019 compared to 2018 and the effective tax rate was 7% and 1% for 2019 and 2018, respectively. The effective tax rate increased primarily as a result of lower amortization of excess deferred income taxes in 2019 and expiring PTCs, slightly offset by the effects of ratemaking. In 2019, $91 million of Oregon’s allocated excess deferred income taxes was amortized pursuant to the Oregon RAC proceeding, whereby a portion of Oregon’s allocated excess deferred income taxes was used to accelerate depreciation for Oregon’s share of certain retired wind equipment due to repowering. In 2018, $127 million of Utah's allocated excess deferred income taxes was amortized pursuant to a 2017 Tax Reform settlement approved by the UPSC, whereby a portion of Utah's allocated excess deferred incomes taxes was used to accelerate depreciation on Utah's share of certain thermal plant units.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Utility margin decreased $198 million for 2018 compared to 2017 primarily due to:

- $180 million of lower retail revenue primarily due to lower average retail rates, including the impact of a lower federal tax rate due to 2017 Tax Reform of $152 million;
- $59 million of higher natural gas-fueled generation volumes;
- $42 million of lower average wholesale prices;
- $41 million of higher purchased electricity costs due to higher prices; and
- $17 million of lower retail revenue from lower retail customer volumes. Retail volumes decreased 0.2% due to the unfavorable impacts of weather on the residential and commercial customer volumes, lower residential usage in all states except Utah, and lower industrial usage in Oregon, Washington and Utah, partially offset by an increase in the average number of commercial and residential customers across the service territory, higher commercial and residential usage in Utah, higher irrigation usage, and higher industrial usage in Wyoming and Idaho.

The decreases above were partially offset by:

- $70 million of higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms;
- $33 million of lower natural gas costs from lower average prices;
- $23 million of higher wholesale revenue due to higher volumes; and
- $20 million of lower coal costs due to lower volumes.

Operations and maintenance increased $4 million for 2018 compared to 2017 primarily due to reserves accrued for 2018 insurance deductibles for third-party property damage and expenses of $7 million and increased maintenance costs partially offset by favorable labor costs.

Depreciation and amortization increased $183 million, or 23%, for 2018 compared to 2017 primarily due to $174 million of accelerated depreciation for Utah's share of certain thermal plant units as ordered by the UPSC in the tax reform docket to offset excess deferred income taxes benefits owed to customers, and higher plant-in-service.

Allowance for borrowed and equity funds increased $22 million, or 71%, for 2018 compared to 2017 primarily due to a prior year true-up that reduced AFUDC rates by $13 million and higher qualified construction work-in-progress balances.

Other, net decreased $19 million, or 70% for 2018 compared to 2017 primarily due to a pension settlement charge of $22 million, lower cash surrender value of company owned life insurance policies of $5 million, partially offset by lower non-service cost components of pension and other postretirement expenses of $9 million.

Income tax expense decreased $355 million, or 99%, for 2018 compared to 2017 and the effective tax rate was 1% and 32% for 2018 and 2017, respectively. The effective tax rate decreased primarily as a result of the reduction in the United States federal corporate income tax rate from 35% to 21%, effective January 1, 2018, and the amortization of $127 million of Utah's allocated excess deferred income taxes pursuant to a 2017 Tax Reform settlement approved by the UPSC, whereby a portion of Utah's allocated excess deferred incomes taxes was used to accelerate depreciation on Utah's share of certain thermal plant units.

Liquidity and Capital Resources

As of December 31, 2019, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$ 30
Credit facilities[1]	1,200
Less:	
Short-term debt	(130)
Tax-exempt bond support	(256)
Net credit facilities	814
Total net liquidity	$ 844
Credit facilities:	
Maturity dates	2022

(1) Refer to Note 7 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, 2019 and 2018 were $1.5 billion and $1.8 billion, respectively. The decrease is primarily due to higher payments for purchased power, timing of payments for operating expenses and lower receipts from retail customers.

Net cash flows from operating activities for the years ended December 31, 2018 and 2017 were $1.8 billion and $1.6 billion, respectively. The increase is primarily due to current year lower payments for income taxes, a prior year pension contribution and higher current year receipts from wholesale customers, partially offset by lower current year receipts from retail customers and higher payments for purchased power.

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, 2019 and 2018 were $(2.2) billion and $(1.3) billion, respectively. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of $918 million.

Net cash flows from investing activities for the years ended December 31, 2018 and 2017 were $(1.3) billion and $(757) million. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of $488 million.

Financing Activities

Short-term Debt

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2019, PacifiCorp had $130 million of short-term debt outstanding at a weighted average interest rate of 2.05%. As of December 31, 2018, PacifiCorp had $30 million of short-term debt outstanding at a weighted average interest rate of 2.85%. For further discussion, refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

In March 2019, PacifiCorp issued $400 million of its 3.50% First Mortgage Bonds due June 2029 and $600 million of its 4.15% First Mortgage Bonds due February 2050. PacifiCorp used a portion of the net proceeds to repay the short-term debt that was partially incurred in January 2019 to repay all of PacifiCorp's $350 million 5.50% First Mortgage Bonds due January 2019. PacifiCorp intends to use the remaining net proceeds to fund capital expenditures and for general corporate purposes.

PacifiCorp made repayments on long-term debt totaling $350 million and $586 million during the years ended December 31, 2019 and 2018, respectively.

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, 2019, PacifiCorp estimated it would be able to issue up to $10.8 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

Credit Facilities

In 2019, PacifiCorp completed a re-offering of variable rate tax-exempt bond obligations totaling $168 million, involving the cancellation, at PacifiCorp's request, of $170 million of letters of credit support by the issuing banks. As a result, PacifiCorp's credit facility support for outstanding variable rate tax-exempt bond obligations increased by $168 million.

Debt Authorizations

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1 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 billion additional first mortgage bonds through October 2021.

Preferred Stock

As of December 31, 2019 and 2018, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In 2019 and 2018, PacifiCorp declared and paid dividends of $175 million and $450 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 lease obligations 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, impacts to customers' rates; changes in environmental and other rules and regulations; 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		
	2017	2018	2019	2020	2021	2022
Transmission system investment	$ 115	$ 75	$ 478	$ 301	$ 218	$ 1,273
Wind investment	11	341	923	1,390	79	388
Operating and other	643	841	774	1,097	1,077	731
Total	$ 769	$ 1,257	$ 2,175	$ 2,788	$ 1,374	$ 2,392

PacifiCorp's 2019 IRP identified a significant increase in renewable resource generation and associated transmission. PacifiCorp has included an estimate of the 2019 IRP resources in its forecast capital expenditures for 2020 through 2022. These estimates are likely to change as a result of the RFP process. PacifiCorp's historical and forecast capital expenditures include the following:

- Transmission system investment primarily reflects initial 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 and investment in additional Energy Gateway Transmission segments expected to be placed in service in 2023. Planned spending for the Aeolus-Bridger/Anticline line totals $139 million in 2020 and $1 million in 2021.
- Wind investment includes the following:
    - Construction of wind-powered generating facilities at PacifiCorp totaled $338 million for 2019 and includes the 1,190 MWs of new wind-powered generating facilities that are expected to be placed in-service in 2020 and the energy production is expected to qualify for 100% of the federal PTCs available for 10 years once the equipment is placed in-service. PacifiCorp's 2019 IRP identified 1,920 MWs of new-wind powered generating resources that are expected to come online in 2023. PacifiCorp anticipates that the additional new wind powered generation will be a mixture of owned and contracted resources. Planned spending for the wind-powered generating facilities totals $1,303 million in 2020, $79 million in 2021 and $388 million in 2022.
    - Repowering existing wind-powered generating facilities at PacifiCorp totaled $585 million in 2019 and $332 million in 2018. Certain repowering projects were placed in service in 2019 and the remaining repowering projects are expected to be placed in-service at various dates in 2020. The energy production from such repowered facilities is expected to qualify for 100% of the federal renewable electricity PTCs available for 10 years following each facility's return to service. Planned spending for certain existing wind-powered generating facilities totals $87 million in 2020.
- Remaining investments relate to operating projects that consist of advanced meter infrastructure costs, routine expenditures for generation, transmission, distribution, planned spend for wildfire mitigation and other infrastructure needed to serve existing and expected demand.

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, 2019 (in millions):

	Payments Due By Periods				
	2020	2021-2022	2023-2024	2025 and After	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 371	$ 1,736	$ 1,497	$ 9,540	$ 13,144
Variable-rate obligations[1]	43	8	174	53	278
Short-term debt, including interest	130	—	—	—	130
Operating and finance lease liabilities	4	10	4	13	31
Interest payments on operating and finance lease liabilities	2	3	2	9	16
Easements	10	24	23	349	406
Asset retirement obligations	19	16	35	403	473
Power purchase agreements - commercially operable[2]:					
Electricity commodity contracts	229	263	230	1,044	1,766
Electricity capacity contracts	35	60	74	640	809
Electricity mixed contracts	15	28	28	126	197
Power purchase agreements - non-commercially operable[2]	7	104	106	987	1,204
Transmission	101	163	127	429	820
Fuel purchase agreements[2]:					
Natural gas supply and transportation	78	56	55	199	388
Coal supply and transportation	754	779	438	576	2,547
Other purchase obligations	1,173	96	70	204	1,543
Other long-term liabilities[3]	26	12	16	57	111
Total contractual cash obligations	$ 2,997	$ 3,358	$ 2,879	$ 14,629	$ 23,863

(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, 2019 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 and local laws and regulations regarding climate change, RPS, air and water quality, emissions performance standards, 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.

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, 2019, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt by Moody's Investor Service and Standard & Poor's Rating Services 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, 2019, PacifiCorp would have been required to post $232 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 12 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.

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 tariff 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 11 and 19 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 recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $1.1 billion and total regulatory liabilities were $3.0 billion as of December 31, 2019. Refer to Note 6 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 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. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. As of December 31, 2019, PacifiCorp had no derivative contracts outstanding related to interest rate risk. Refer to Notes 12 and 13 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 three years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. As of December 31, 2019, PacifiCorp had a net derivative liability of $63 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 three 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, 2019, 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, 2019, PacifiCorp had $62 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, 2019, PacifiCorp recognized a net liability totaling $101 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2019, 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 $402 million and $21 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 10 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, 2019.

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 evaluates the investment allocation between return-seeking investment and fixed income securities based on the funded status of the plan and 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, 2019 Benefit Obligations:				
Discount rate	$ (59)	$ 65	$ (12)	$ 13
Effect on 2019 Periodic Cost:				
Discount rate	$ —	$ —	$ 1	$ (1)
Expected rate of return on plan assets	(5)	5	(2)	2

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

Income Taxes

In determining PacifiCorp's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory commissions. 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. Refer to Note 9 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers in certain state jurisdictions. As of December 31, 2019, these amounts were recognized as a net regulatory liability of $1.7 billion 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 the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $245 million as of December 31, 2019. 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 12 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, 2019, 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 $14 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):

	2019
Minimum VaR (measured)	$ 7
Average VaR (calculated)	9
Maximum VaR (measured)	16

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2019. 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 $47 million and $59 million as of December 31, 2019 and 2018, 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, 2019:			
Total commodity derivative contracts	$ (63)	$ (44)	$ (82)
As of December 31, 2018			
Total commodity derivative contracts	$ (97)	$ (92)	$ (102)

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, 2019 and 2018, a regulatory asset of $62 million and $96 million, respectively, was recorded related to the net derivative liability of $63 million and $97 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 7, 8 and 13 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, 2019 and 2018, PacifiCorp had short- and long-term variable-rate obligations totaling $385 million and $285 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, 2019 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, 2019 and 2018.

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, 2019, PacifiCorp's aggregate credit exposure with wholesale energy supply and marketing counterparties included counterparties having non-investment grade, internally rated credit ratings. Substantially all of these non-investment grade, internally rated counterparties are associated with long-duration solar and wind power purchase agreements from facilities that have not yet achieved commercial operation and for which PacifiCorp has no obligation should the facilities not achieve commercial operation.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2019 and 2018, 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, 2019, 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 PacifiCorp as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of PacifiCorp's management. Our responsibility is to express an opinion on PacifiCorp'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 PacifiCorp 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. PacifiCorp 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 PacifiCorp'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 21, 2020

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 30	$ 77
Trade receivables, net	644	640
Other receivables, net	70	92
Inventories	394	417
Other current assets	152	133
Total current assets	1,290	1,359
Property, plant and equipment, net	20,973	19,570
Regulatory assets	1,060	1,076
Other assets	374	308
Total assets	$ 23,697	$ 22,313

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,	
	2019	**2018**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 679	$ 597
Accrued interest	116	114
Accrued property, income and other taxes	96	75
Accrued employee expenses	75	79
Short-term debt	130	30
Current portion of long-term debt	38	350
Regulatory liabilities	56	77
Other current liabilities	170	193
Total current liabilities	1,360	1,515
Long-term debt	7,620	6,665
Regulatory liabilities	2,913	2,978
Deferred income taxes	2,563	2,543
Other long-term liabilities	804	767
Total liabilities	15,260	14,468
Commitments and contingencies (Note 14)		
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	3,972	3,377
Accumulated other comprehensive loss, net	(16)	(13)
Total shareholders' equity	8,437	7,845
Total liabilities and shareholders' equity	$ 23,697	$ 22,313

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,		
	2019	**2018**	**2017**
Operating revenue	$ 5,068	$ 5,026	$ 5,237
Operating expenses:			
Cost of fuel and energy	1,795	1,757	1,770
Operations and maintenance	1,048	1,038	1,034
Depreciation and amortization	954	979	796
Property and other taxes	199	201	197
Total operating expenses	3,996	3,975	3,797
Operating income	1,072	1,051	1,440
Other income (expense):			
Interest expense	(401)	(384)	(381)
Allowance for borrowed funds	36	18	11
Allowance for equity funds	72	35	20
Interest and dividend income	21	15	11
Other, net	32	8	27
Total other expense	(240)	(308)	(312)
Income before income tax expense	832	743	1,128
Income tax expense	61	5	360
Net income	$ 771	$ 738	$ 768

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,		
	2019	**2018**	**2017**
Net income	$ 771	$ 738	$ 768
Other comprehensive (loss) income, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of ($1), $1 and $3	(3)	2	(3)
Comprehensive income	$ 768	$ 740	$ 765

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, 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
Net income	—	—	—	738	—	738
Other comprehensive income	—	—	—	—	2	2
Common stock dividends declared	—	—	—	(450)	—	(450)
Balance, December 31, 2018	2	—	4,479	3,377	(13)	7,845
Net income	—	—	—	771	—	771
Other comprehensive loss	—	—	—	(1)	(3)	(4)
Common stock dividends declared	—	—	—	(175)	—	(175)
Balance, December 31, 2019	$ 2	$ —	$ 4,479	$ 3,972	$ (16)	$ 8,437

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,		
	2019	2018	2017
Cash flows from operating activities:			
Net income	$ 771	$ 738	$ 768
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	954	979	796
Allowance for equity funds	(72)	(35)	(20)
Changes in regulatory assets and liabilities	(55)	87	18
Deferred income taxes and amortization of investment tax credits	(131)	(199)	70
Other, net	20	5	9
Changes in other operating assets and liabilities:			
Trade receivables, other receivables and other assets	14	62	67
Inventories	23	16	10
Derivative collateral, net	12	15	(6)
Accrued property, income and other taxes, net	22	60	(48)
Accounts payable and other liabilities	(11)	83	(62)
Net cash flows from operating activities	1,547	1,811	1,602
Cash flows from investing activities:			
Capital expenditures	(2,175)	(1,257)	(769)
Other, net	11	5	12
Net cash flows from investing activities	(2,164)	(1,252)	(757)
Cash flows from financing activities:			
Proceeds from long-term debt	989	593	—
Repayments of long-term debt	(350)	(586)	(52)
Net proceeds from (repayments of) short-term debt	100	(50)	(190)
Dividends paid	(175)	(450)	(600)
Other, net	(3)	(3)	(7)
Net cash flows from financing activities	561	(496)	(849)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(56)	63	(4)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	92	29	33
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 36	$ 92	$ 29

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 recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Cash Equivalents 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 cash and cash equivalents consist substantially of funds representing escrow accounts for disputes, vendor retention, custodial and nuclear decommissioning funds. 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, 2019 and 2018, 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.

Equity Method Investments

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 collectability 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. As of December 31, 2019 and 2018, the allowance for doubtful accounts totaled $8 million and is included in trade receivables, net on the Consolidated Balance Sheets.

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, supplies and fuel stocks and 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

PacifiCorp 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 supports PacifiCorp's regulated businesses the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of office buildings, natural gas pipeline facilities, and generating facilities. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize lease obligations and corresponding right-of-use assets for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets will be evaluated for impairment in line with ASC 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

PacifiCorp's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

PacifiCorp uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. 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.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of revenue recognized in accordance with ASC 815, "Derivatives and Hedging."

Revenue recognized is equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date and includes billed and unbilled amounts. As of December 31, 2019 and 2018, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $245 million and $229 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. 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.

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. Changes in deferred income tax assets and liabilities that are associated with 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 or as otherwise approved by PacifiCorp's various regulatory commissions. 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 commissions. Investment tax credits are included in other long-term liabilities on the Consolidated Balance Sheets and were $11 million and $13 million as of December 31, 2019 and 2018, 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 commissions. 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.

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.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("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 on 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. Following the issuance of ASU No. 2016-02, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2016-02 but did not change the core principle of the guidance. PacifiCorp has elected to utilize various practical expedients available to adopt ASU No. 2016-02, including (1) the package of three not requiring a reassessment of (i) whether any expired or existing contracts are or contain leases; (ii) the lease classification for any expired or existing leases; and (iii) initial direct costs for any existing leases; (2) using hindsight in determining the lease term; and (3) not requiring a reassessment of whether existing or expired land easements that were not previously accounted for as leases under ASC Topic 840 are or contain a lease under ASC Topic 842. PacifiCorp adopted this guidance for all applicable contracts in effect as of January 1, 2019 under a modified retrospective method and the adoption did not have a cumulative effect impact at the date of initial adoption.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2019	2018
Utility Plant:			
Generation	14 - 67 years	$ 12,509	$ 12,606
Transmission	58 - 75 years	6,482	6,357
Distribution	20 - 70 years	7,307	7,030
Intangible plant[1]	5 - 75 years	1,016	970
Other	5 - 60 years	1,449	1,436
Utility plant in service		28,763	28,399
Accumulated depreciation and amortization		(9,803)	(10,034)
Utility plant in service, net		18,960	18,365
Other non-regulated, net of accumulated depreciation and amortization	46 years	10	10
Plant, net		18,970	18,375
Construction work-in-progress		2,003	1,195
Property, plant and equipment, net		$ 20,973	$ 19,570

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 3.3%, 3.5% and 2.9% for the years ended December 31, 2019, 2018 and 2017, respectively, including the impacts of accelerated depreciation for Oregon's share of certain wind equipment retired as a result of wind repowering projects placed into service in 2019 and accelerated depreciation for Utah's share of certain thermal plant units in 2018.

PacifiCorp filed a depreciation study in 2018 with all of its state public utility commissions, except the California Public Utilities Commission. PacifiCorp is currently working with the commissions and interested parties and anticipates revised depreciation rates to be effective January 1, 2021.

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 dedicated 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, 2019 and 2018, and accumulated depreciation of $132 million and $127 million as of December 31, 2019 and 2018, 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, 2019 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,476	$ 677	$ 9
Hunter No. 1	94	484	193	1
Hunter No. 2	60	305	121	2
Wyodak	80	473	243	1
Colstrip Nos. 3 and 4	10	254	137	2
Hermiston	50	181	92	5
Craig Nos. 1 and 2	19	368	252	—
Hayden No. 1	25	75	39	—
Hayden No. 2	13	43	23	—
Transmission and distribution facilities	Various	808	255	103
Total		$ 4,467	$ 2,032	$ 123

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Consolidated Balance Sheet (in millions):

	As of December 31, 2019
Right-of-use assets:	
Operating leases	$ 12
Finance leases	19
Total right-of-use assets	$ 31
Lease liabilities:	
Operating leases	$ 12
Finance leases	19
Total lease liabilities	$ 31

The following table summarizes PacifiCorp's lease costs (in millions):

	Year Ended December 31, 2019
Variable	$ 77
Operating	3
Finance:	
Amortization	1
Interest	2
Short-term	2
Total lease costs	$ 85
Weighted-average remaining lease term (years):	
Operating leases	14.0
Finance leases	9.1
Weighted-average discount rate:	
Operating leases	3.7%
Finance leases	10.6%

Cash payments associated with operating and finance lease liabilities approximated lease cost for the year ended December 31, 2019.

PacifiCorp has the following remaining lease commitments as of (in millions):

	December 31, 2019		
	Operating	Finance	Total
2020	$ 2	$ 3	$ 5
2021	2	7	9
2022	2	3	5
2023	2	2	4
2024	1	2	3
Thereafter	7	14	21
Total undiscounted lease payments	16	31	47
Less - amounts representing interest	(4)	(12)	(16)
Lease liabilities	$ 12	$ 19	$ 31

	December 31, 2018[(1)]		
	Operating	Capital	Total
2019	$ 3	$ 4	$ 7
2020	3	4	7
2021	3	7	10
2022	2	3	5
2023	2	2	4
Thereafter	7	16	23
Total undiscounted lease payments	$ 20	$ 36	$ 56

(1) Amounts included for comparability and accounted for in accordance with ASC 840, "Leases".

(6) 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	2019	2018
Employee benefit plans[1]	19 years	$ 422	$ 448
Utah mine disposition[2]	Various	125	136
Unamortized contract values	4 years	60	79
Deferred net power costs	2 years	106	62
Unrealized loss on derivative contracts	3 years	62	96
Asset retirement obligation	28 years	140	119
Other	Various	208	172
Total regulatory assets		$ 1,123	$ 1,112
Reflected as:			
Current assets		$ 63	$ 36
Noncurrent assets		1,060	1,076
Total regulatory assets		$ 1,123	$ 1,112

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

(2) Amounts 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 $609 million and $636 million as of December 31, 2019 and 2018, 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	2019	2018
Cost of removal[1]	26 years	$ 1,019	$ 994
Deferred income taxes[2]	Various	1,653	1,803
Other	Various	297	258
Total regulatory liabilities		$ 2,969	$ 3,055
Reflected as:			
Current liabilities		$ 56	$ 77
Noncurrent liabilities		2,913	2,978
Total regulatory liabilities		$ 2,969	$ 3,055

(1) Amounts represent estimated costs, as accrued through depreciation rates, 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 of being 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.

(7) Short-term Debt and Credit Facilities

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

2019:		
Credit facilities	$	1,200
Less:		
Short-term debt		(130)
Tax-exempt bond support		(256)
Net credit facilities	$	814
2018:		
Credit facilities	$	1,200
Less:		
Short-term debt		(30)
Tax-exempt bond support		(89)
Net credit facilities	$	1,081

As of December 31, 2019, PacifiCorp was in compliance with the covenants of its credit facilities and letter of credit arrangements.

PacifiCorp has a $600 million unsecured credit facility expiring in June 2022 and a $600 million unsecured credit facility expiring in June 2022 with one remaining 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, 2019 and 2018, the weighted average interest rate on commercial paper borrowings outstanding was 2.05% and 2.85%, 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, 2019 and 2018, PacifiCorp had $13 million and $184 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2019 and 2018, $13 million and $14 million, respectively, support certain transactions required by third parties and generally 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.

(8) Long-term Debt

PacifiCorp's long-term debt was as follows as of December 31 (dollars in millions):

	2019			2018	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
2.95% to 8.53%, due through 2024	$ 1,899	$ 1,895	4.09%	$ 2,244	4.31%
3.35% to 6.71%, due 2025 to 2026	350	349	4.31	348	4.31
3.50% to 7.70%, due 2029 to 2031	700	696	5.30	298	7.70
5.25% to 6.35%, due 2034 to 2038	2,350	2,338	5.96	2,338	5.96
4.10% to 6.00%, due 2039 to 2042	950	939	5.40	939	5.40
4.13% to 4.15%, due 2049 to 2050	1,200	1,186	4.14	593	4.13
Variable-rate series, tax-exempt bond obligations (2019-1.60% to 1.80%; 2018-1.67% to 1.85%):					
Due 2020	38	38	1.78	38	1.85
Due 2024(1)(2)	143	143	1.73	142	1.68
Due 2025(1)	25	24	1.75	25	1.75
Due 2024 to 2025(2)	50	50	1.63	50	1.75
Total long-term debt	$ 7,705	$ 7,658		$ 7,015	

Reflected as:

	2019	2018
Current portion of long-term debt	$ 38	$ 350
Long-term debt	7,620	6,665
Total long-term debt	$ 7,658	$ 7,015

1) Supported by $170 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2018. These arrangements were canceled in 2019.

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 Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional $1.0 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 (SEC) to issue up to $1.0 billion additional first mortgage bonds through October 2021.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $29 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2019.

As of December 31, 2019, the annual principal maturities of long-term debt for 2020 and thereafter are as follows (in millions):

	Long-term Debt
2020	$ 38
2021	420
2022	605
2023	449
2024	591
Thereafter	5,602
Total	7,705
Unamortized discount and debt issuance costs	(47)
Total	$ 7,658

(9) Income Taxes

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

	2019	2018	2017
Current:			
Federal	$ 158	$ 164	$ 249
State	34	40	41
Total	192	204	290
Deferred:			
Federal	(132)	(187)	59
State	4	(9)	15
Total	(128)	(196)	74
Investment tax credits	(3)	(3)	(4)
Total income tax expense	$ 61	$ 5	$ 360

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:

	2019	2018	2017
Federal statutory income tax rate	21%	21%	35%
State income taxes, net of federal income tax benefit	3	4	3
Amortization of excess deferred income taxes	(11)	(17)	—
Effects of ratemaking	(2)	—	1
Federal income tax credits	(3)	(7)	(5)
Other	(1)	—	(2)
Effective income tax rate	7%	1%	32%

Income tax credits relate primarily to production tax credits ("PTC") earned by PacifiCorp's wind-powered generating facilities. Federal renewable electricity PTCs 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. Amortization of excess deferred income taxes is primarily attributable to the amortization of $91 million of Oregon allocated excess deferred income taxes pursuant to the Oregon Renewable Adjustment Clause settlement, whereby a portion of Oregon allocated excess deferred income taxes was used to accelerate depreciation on Oregon's share of certain repowered wind facilities. Amortization of excess deferred income taxes in 2018 is primarily attributable to the amortization of $127 million of Utah allocated excess deferred income taxes pursuant to a 2017 Tax Reform settlement approved by the UPSC, whereby a portion of Utah allocated excess deferred income taxes was used to accelerate depreciation on Utah's share of certain thermal plant units.

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

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 731	$ 752
Employee benefits	83	91
Derivative contracts and unamortized contract values	33	45
State carryforwards	70	77
Asset retirement obligations	61	53
Other	68	56
	1,046	1,074
Deferred income tax liabilities:		
Property, plant and equipment	(3,312)	(3,335)
Regulatory assets	(276)	(273)
Other	(21)	(9)
	(3,609)	(3,617)
Net deferred income tax liability	$ (2,563)	$ (2,543)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2019 (in millions):

	State
Net operating loss carryforwards	$ 1,140
Deferred income taxes on net operating loss carryforwards	$ 51
Expiration dates	2023 - 2032
Tax credit carryforwards	$ 19
Expiration dates	2020 - indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2011. The statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2011, with the exception of California, Utah and Oregon, for which the statutes have expired through December 31, 2009. In addition, Idaho's statute of limitations has expired through December 31, 2015, except for the impact of any federal audit adjustments. 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 statute of limitations is not closed.

(10) 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.

Defined 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.

During 2018, the Retirement Plan incurred a settlement charge of $22 million as a result of excess lump sum distributions over the defined threshold for the year ended December 31, 2018.

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		
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
Service cost	$ —	$ —	$ —	$ 2	$ 2	$ 2
Interest cost	44	43	49	12	11	14
Expected return on plan assets	(67)	(72)	(72)	(21)	(21)	(21)
Settlement	—	22	—	—	—	—
Net amortization	11	13	14	—	(6)	(6)
Net periodic benefit (credit) cost	$ (12)	$ 6	$ (9)	$ (7)	$ (14)	$ (11)

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	
	2019	**2018**	**2019**	**2018**
Plan assets at fair value, beginning of year	$ 942	$ 1,111	$ 297	$ 332
Employer contributions	4	4	1	1
Participant contributions	—	—	5	5
Actual return on plan assets	181	(52)	55	(16)
Settlement	—	(52)	—	—
Benefits paid	(91)	(69)	(24)	(25)
Plan assets at fair value, end of year	$ 1,036	$ 942	$ 334	$ 297

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

	Pension		Other Postretirement	
	2019	2018	2019	2018
Benefit obligation, beginning of year	$ 1,105	$ 1,251	$ 298	$ 331
Service cost	—	—	2	2
Interest cost	44	43	12	11
Participant contributions	—	—	5	5
Actuarial loss (gain)	109	(68)	11	(26)
Settlement	—	(52)	—	—
Benefits paid	(91)	(69)	(24)	(25)
Benefit obligation, end of year	$ 1,167	$ 1,105	$ 304	$ 298
Accumulated benefit obligation, end of year	$ 1,167	$ 1,105		

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	
	2019	2018	2019	2018
Plan assets at fair value, end of year	$ 1,036	$ 942	$ 334	$ 297
Less - Benefit obligation, end of year	1,167	1,105	304	298
Funded status	$ (131)	$ (163)	$ 30	$ (1)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 7	$ 3	$ 30	$ —
Other current liabilities	(4)	(4)	—	—
Other long-term liabilities	(134)	(162)	—	(1)
Amounts recognized	$ (131)	$ (163)	$ 30	$ (1)

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 $57 million and $52 million as of December 31, 2019 and 2018, respectively. These assets are not included in the plan assets in the above table, but are reflected in cash and cash equivalents, totaling $- million and $1 million as of December 31, 2019 and 2018, respectively, and noncurrent other assets, totaling $57 million and $51 million as of December 31, 2019 and 2018, respectively, on the Consolidated Balance Sheets.

The projected benefit obligation and the accumulated benefit obligation for the pension plan were both in excess of the fair value of the plan assets as of December 31, 2019.

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	
	2019	2018	2019	2018
Net loss (gain)	$ 442	$ 461	$ (26)	$ (2)
Regulatory deferrals	1	(1)	6	7
Total	$ 443	$ 460	$ (20)	$ 5

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2019 and 2018 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2017	$ 418	$ 20	$ 438
Net loss (gain) arising during the year	59	(2)	57
Net amortization	(12)	(1)	(13)
Settlement	(22)	—	(22)
Total	25	(3)	22
Balance, December 31, 2018	443	17	460
Net (gain) loss arising during the year	(11)	5	(6)
Net amortization	(10)	(1)	(11)
Total	(21)	4	(17)
Balance, December 31, 2019	$ 422	$ 21	$ 443

	Regulatory Asset (Liability)
Other Postretirement	
Balance, December 31, 2017	$ (11)
Net loss arising during the year	10
Net amortization	6
Total	16
Balance, December 31, 2018	5
Net gain arising during the year	(25)
Net amortization	—
Total	(25)
Balance, December 31, 2019	$ (20)

Plan Assumptions

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

	Pension			Other Postretirement		
	2019	2018	2017	2019	2018	2017
Benefit obligations as of December 31:						
Discount rate	3.25%	4.25%	3.60%	3.20%	4.25%	3.60%
Rate of compensation increase	N/A	N/A	N/A	N/A	N/A	N/A
Interest crediting rates for cash balance plan (1)(2)(3)	2.27%	3.40%	1.61%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.25%	3.60%	4.05%	4.25%	3.60%	4.05%
Expected return on plan assets	7.00	7.00	7.25	6.86	6.86	7.25
Rate of compensation increase	N/A	N/A	N/A	N/A	N/A	N/A

(1) 2019 Cash Balance Interest Crediting Rate assumption is 2.27% for 2020-2021 and 2.10% for 2022 and all future years for nonunion participants and 2.16% for 2020-2021 and 2.70% for 2022+ for union participants.

(2) 2018 Cash Balance Interest Crediting Rate assumption was 3.40% for 2019 and all future years for nonunion participants and 3.15% for 2019-2020 and 3.25% for 2021+ for union participants.

(3) 2017 Cash Balance Interest Crediting Rate assumption was 2.26% for 2018-2019 and 1.60% for 2020+ for nonunion participants and 2.78% for 2018-2019 and 2.60% for 2020+ for union participants.

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 2020. 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 evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plan.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2020 through 2024 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2020	$ 112	$ 27
2021	98	24
2022	94	23
2023	89	23
2024	83	21
2025-2029	350	94

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, 2019:

	Pension[(1)]	**Other Postretirement**[(1)]
	%	%
Debt securities[(2)]	30 - 43	33 - 37
Equity securities[(2)]	48 - 65	62 - 66
Limited partnership interests	6 - 12	1 - 3

(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, 2019:				
Cash equivalents	$ —	$ 24	$ —	$ 24
Debt securities:				
United States government obligations	21	—	—	21
Corporate obligations	—	94	—	94
Municipal obligations	—	10	—	10
Agency, asset and mortgage-backed obligations	—	42	—	42
Equity securities:				
United States companies	355	—	—	355
International companies	15	—	—	15
Investment funds[(2)]	55	—	—	55
Total assets in the fair value hierarchy	$ 446	$ 170	$ —	616
Investment funds[(2)] measured at net asset value				327
Limited partnership interests[(3)] measured at net asset value				93
Investments at fair value				$ 1,036
As of December 31, 2018:				
Cash equivalents	$ —	$ 11	$ —	$ 11
Debt securities:				
United States government obligations	4	—	—	4
International government obligations		1		1
Corporate obligations	—	88	—	88
Municipal obligations	—	10	—	10
Agency, asset and mortgage-backed obligations	—	43	—	43
Equity securities:				
United States companies	327	—	—	327
International companies	15	—	—	15
Investment funds[(2)]	54	—	—	54
Total assets in the fair value hierarchy	$ 400	$ 153	$ —	553
Investment funds[(2)] measured at net asset value				285
Limited partnership interests[(3)] measured at net asset value				104
Investments at fair value				$ 942

(1) Refer to Note 13 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 55% and 45% respectively, for both 2019 and 2018, and are invested in United States and international securities of approximately 51% and 49%, respectively, for 2019 and 68% and 32%, respectively, for 2018.

(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, 2019:				
Cash and cash equivalents	$ 8	$ 1	$ —	$ 9
Debt securities:				
United States government obligations	12	—	—	12
Corporate obligations	—	26	—	26
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	22	—	22
Equity securities:				
United States companies	74	—	—	74
International companies	4	—	—	4
Investment funds[2]	44	—	—	44
Total assets in the fair value hierarchy	142	51	—	193
Investment funds[2] measured at net asset value				136
Limited partnership interests[3] measured at net asset value				5
Investments at fair value				$ 334
As of December 31, 2018:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	3	—	—	3
Corporate obligations	—	23	—	23
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	17	—	17
Equity securities:				
United States companies	83	—	—	83
International companies	4	—	—	4
Investment funds[2]	38	—	—	38
Total assets in the fair value hierarchy	132	43	—	175
Investment funds[2] measured at net asset value				116
Limited partnership interests[3] measured at net asset value				6
Investments at fair value				$ 297

(1) Refer to Note 13 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 56% and 44%, respectively, for 2019 and 59% and 41%, respectively, for 2018, and are invested in United States and international securities of approximately 79% and 21%, respectively, for 2019 and 90% and 10%, respectively, for 2018.

(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 United Mine Workers of America ("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 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.

The following table presents PacifiCorp'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**	**2019**	**2018**	**2017**	**Funding improvement plan**	**Surcharge imposed under PPA [1]**	**2019**	**2018**	**2017**	**Year contributions to plan exceeded more than 5% of total contributions[2]**
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 7	$ 7	$ 7	2017, 2016, 2015

(1) PacifiCorp's minimum contributions to the plan are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements, subject to ERISA minimum funding requirements.

(2) For the Local 57 Trust Fund, information is for plan years beginning July 1, 2017, 2016 and 2015. Information for the plan year beginning July 1, 2018 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in 2023.

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, 2019, 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 $40 million, $39 million and $39 million for the years ended December 31, 2019, 2018 and 2017, respectively.

(11) 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 $1,019 million and $994 million as of December 31, 2019 and 2018, respectively.

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

	2019	2018
Beginning balance	$ 227	$ 215
Change in estimated costs	27	9
Additions	9	—
Retirements	(15)	(5)
Accretion	9	8
Ending balance	$ 257	$ 227
Reflected as:		
Other current liabilities	$ 19	$ 21
Other long-term liabilities	238	206
	$ 257	$ 227

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.

(12) 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 13 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of 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, 2019:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 15	$ 2	$ 4	$ —	$ 21
Commodity liabilities	(3)	—	(31)	(50)	(84)
Total	12	2	(27)	(50)	(63)
Total derivatives	12	2	(27)	(50)	(63)
Cash collateral receivable	—	—	20	27	47
Total derivatives - net basis	$ 12	$ 2	$ (7)	$ (23)	$ (16)
As of December 31, 2018:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 36	$ 4	$ 10	$ 1	$ 51
Commodity liabilities	(9)	(1)	(67)	(71)	(148)
Total	27	3	(57)	(70)	(97)
Total derivatives	27	3	(57)	(70)	(97)
Cash collateral (payable) receivable	(2)	—	16	45	59
Total derivatives - net basis	$ 25	$ 3	$ (41)	$ (25)	$ (38)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2019 and 2018, a regulatory asset of $62 million and $96 million, respectively, was recorded related to the net derivative liability of $63 million and $97 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):

	2019	2018	2017
Beginning balance	$ 96	$ 101	$ 73
Changes in fair value recognized in regulatory assets	(37)	12	47
Net (losses) gains reclassified to operating revenue	(34)	(68)	9
Net gains (losses) reclassified to energy costs	37	51	(28)
Ending balance	$ 62	$ 96	$ 101

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	2019	2018
Electricity sales	Megawatt hours	(2)	(6)
Natural gas purchases	Decatherms	129	117

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 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. As of December 31, 2019, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt by Moody's Investor Service and Standard & Poor's Rating Services were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $80 million and $113 million as of December 31, 2019 and 2018, respectively, for which PacifiCorp had posted collateral of $47 million and $61 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, 2019 and 2018, PacifiCorp would have been required to post $27 million and $35 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.

(13) 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, 2019:					
Assets:					
Commodity derivatives	$ —	$ 21	$ —	$ (7)	$ 14
Money market mutual funds[2]	23	—	—	—	23
Investment funds	25	—	—	—	25
	$ 48	$ 21	$ —	$ (7)	$ 62
Liabilities - Commodity derivatives	$ —	$ (84)	$ —	$ 54	$ (30)
As of December 31, 2018:					
Assets:					
Commodity derivatives	$ —	$ 51	$ —	$ (23)	$ 28
Money market mutual funds [2]	69	—	—	—	69
Investment funds	24	—	—	—	24
	$ 93	$ 51	$ —	$ (23)	$ 121
Liabilities - Commodity derivatives	$ —	$ (148)	$ —	$ 82	$ (66)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $47 million and $59 million as of December 31, 2019 and 2018, 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 three 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 three 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 12 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):

	2019		2018	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,658	$ 9,280	$ 7,015	$ 7,833

(14) 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 is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSA"), which is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA does not guarantee dam removal. Instead, it establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can occur consistent with the settlement's terms. For PacifiCorp, the key elements of the settlement include: (1) a contribution from PacifiCorp's Oregon and California customers capped at $200 million plus $250 million in California bond funds; (2) complete indemnification from harms associated with dam removal; (3) transfer of the Federal Energy Regulatory Commission ("FERC") license to a third-party dam removal entity, the Klamath River Renewal Corporation ("KRRC"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

In September 2016, the KRRC and PacifiCorp filed a joint application with the FERC to transfer the license for the four mainstem Klamath dams from PacifiCorp to the KRRC. Over the past two years, the KRRC has been supplementing the application with additional information about its financial, technical, and legal capacity to become the licensee. In July 2019, the KRRC provided the FERC with additional information about its financial capacity to become a licensee, including updated cost estimates, and its insurance, bonding and liability transfer package. The FERC is evaluating the KRRC's information and the proposed license transfer. The KRRC will continue to refine its insurance, bonding and liability transfer package, and PacifiCorp will review the KRRC's capacity to fulfill its indemnity obligation under the KHSA. If certain conditions in the amended KHSA are not satisfied (e.g., inadequate funding or inability of KRRC to satisfy its indemnification obligation) and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

The United States Court of Appeals for the District of Columbia Circuit issued a decision in the *Hoopa Valley Tribe v. FERC* litigation, in January 2019, finding that the states of California and Oregon have waived their Clean Water Act, Section 401, water quality certification authority over the Klamath hydroelectric project relicensing. This decision has the potential to limit the ability of the States to impose water quality conditions on new and relicensed projects. Environmental interests, supported by California, Oregon and other states, asked the court to rehear the case, which was denied. Subsequently, environmental groups, supported by numerous states, filed a petition for certiorari before the United States Supreme Court, which was denied on December 9, 2019, thereby allowing the circuit court opinion to stand as a final and unappealable decision.

As of December 31, 2019, PacifiCorp's assets included $29 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 in Utah, Wyoming and Idaho through December 31, 2022.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $168 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, 2019 are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 279	$ 177	$ 174	$ 168	$ 164	$ 1,810	$ 2,772
Purchased electricity contracts - non-commercially operable	7	52	52	53	53	987	1,204
Fuel contracts	832	519	316	245	248	775	2,935
Construction commitments	844	6	—	—	4	—	854
Transmission	101	86	77	71	56	429	820
Easements	10	12	12	12	11	349	406
Maintenance, service and other contracts	329	49	41	34	32	204	689
Total commitments	$ 2,402	$ 901	$ 672	$ 583	$ 568	$ 4,554	$ 9,680

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 solar or 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. Refer to Note 5 for information on lease commitments.

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 2019, 2018 and 2017 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.

Easements

PacifiCorp has non-cancelable easements for land on which certain of its assets, primarily wind-powered generating facilities, are located.

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.

(15) Revenue from Contracts with Customers

The following table summarizes PacifiCorp's revenue by regulated energy, with further disaggregation of regulated energy by customer class, for the years ended December 31 (in millions):

	2019	2018
Customer Revenue:		
Retail:		
Residential	$ 1,783	$ 1,737
Commercial	1,522	1,513
Industrial	1,176	1,172
Other retail	230	234
Total retail	4,711	4,656
Wholesale	99	55
Transmission	98	103
Other Customer Revenue	78	76
Total Customer Revenue	4,986	4,890
Other revenue	82	136
Total operating revenue	$ 5,068	$ 5,026

(16) 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, 2019 and 2018. 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, 2019 and 2018.

(17) Common Shareholder's Equity

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, 2019, 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. As of December 31, 2019, PacifiCorp's actual common equity percentage, as calculated under this measure, was 53%, and PacifiCorp would have been permitted to dividend $2.4 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, 2019, 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 7.

(18) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of $16 million and $13 million as of December 31, 2019 and 2018, respectively.

(19) 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 $81 million and $100 million as of December 31, 2019 and 2018, respectively. Refer to Note 21 for information regarding related-party transactions with Bridger Coal.

(20) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and 2018, as presented in the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	2019	2018
Cash and cash equivalents	$ 30	$ 77
Restricted cash included in other current assets	4	13
Restricted cash included in other assets	2	2
Total cash and cash equivalents and restricted cash and cash equivalents	$ 36	$ 92

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

	2019	2018	2017
Interest paid, net of amounts capitalized	$ 340	$ 347	$ 350
Income taxes paid, net	$ 171	$ 144	$ 340
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 293	$ 184	$ 147

(21) Related-Party Transactions

PacifiCorp has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to PacifiCorp by BHE and its subsidiaries under this agreement totaled $10 million, $12 million and $11 million during the years ended December 31, 2019, 2018 and 2017, respectively. Payables associated with these administrative services were immaterial as of December 31, 2019 and 2018, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under this agreement, as well as receivables associated with these administrative services, were immaterial during the years ended December 31, 2019, 2018 and 2017, 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 $7 million, $8 million and $6 million during the years ended December 31, 2019, 2018 and 2017, respectively. Payables associated with these services were immaterial as of December 31, 2019 and 2018, respectively. Amounts charged by PacifiCorp to subsidiaries of BHE for wholesale electricity sales in the ordinary course of business were immaterial during the years ended December 31, 2019, 2018 and 2017, 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, $33 million and $35 million during the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019 and 2018, PacifiCorp had immaterial amounts 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 payable to BHE were $31 million and $10 million as of December 31, 2019 and 2018, respectively. For the years ended December 31, 2019, 2018 and 2017, cash paid for federal and state income taxes to BHE totaled $171 million, $144 million and $340 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2019, 2018 and 2017, PacifiCorp charged Bridger Coal immaterial amounts, primarily for administrative support and management services provided by PacifiCorp to Bridger Coal. Receivables for these services, as well as for certain expenses paid by PacifiCorp and reimbursed by Bridger Coal, were immaterial as of December 31, 2019 and 2018, respectively. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2019, 2018 and 2017, coal purchases from PacifiCorp's equity investees totaled $155 million, $163 million and $170 million, respectively. Payables to PacifiCorp's equity investees were $12 million and $13 million as of December 31, 2019 and 2018, respectively.

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

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 during the periods included herein. 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, usage trends and other factors. This discussion should be read in conjunction with MidAmerican Funding's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements and MidAmerican Energy's historical Financial Statements and Notes to Financial Statements each in Item 8 of this Form 10-K. MidAmerican Funding's and MidAmerican Energy'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 2019 was $793 million, an increase of $111 million, or 16%, compared to 2018 primarily due to a higher income tax benefit of $116 million from higher PTCs of $70 million and the effects of ratemaking, higher electric utility margin of $42 million, higher allowances for equity and borrowed funds of $32 million and higher investment earnings of $20 million, partially offset by higher interest expense of $54 million and higher depreciation and amortization expense of $30 million due to wind-powered generation and other plant placed in-service offset by $46 million of lower Iowa revenue sharing. Electric utility margin increased due to lower fuel costs from higher wind generation, higher recoveries through bill riders (substantially offset in cost of fuel and energy, operations and maintenance expense and income tax benefit) and higher retail customer volumes. Electric retail customer volumes increased 1.4% as an increase in industrial volumes of 4.0% was largely offset by lower residential volumes from the less favorable impact of weather and lower overall customer usage.

MidAmerican Energy's net income for 2018 was $682 million, an increase of $77 million, or 13%, compared to 2017 primarily due to higher electric utility margin of $122 million, a higher income tax benefit of $72 million, primarily due to a $21 million increase in PTCs, a lower federal tax rate and a 2017 charge of $7 million from the Tax Cuts and Jobs Act enacted on December 22, 2017 (the "2017 Tax Reform"), and higher allowance for borrowed and equity funds of $17 million, partially offset by higher depreciation and amortization of $109 million due to wind-powered generation and other plant placed in-service and $44 million of higher Iowa revenue sharing, higher operations and maintenance expense of $12 million and higher interest expense of $13 million. Electric utility margin increased due to higher recoveries through bill riders of $127 million (substantially offset in cost of fuel and energy, operations and maintenance expense and income tax benefit), higher retail customer volumes of 5.6%, largely due to industrial growth and the favorable impact of weather and higher wholesale revenue, partially offset by lower average retail rates of $126 million, predominantly from the impact of a lower federal tax rate due to 2017 Tax Reform, and higher generation and purchased power costs.

MidAmerican Funding -

MidAmerican Funding's net income for 2019 was $781 million, an increase of $112 million, or 17%, compared to 2018. The increase was primarily due to the changes in MidAmerican Energy's earnings discussed above. MidAmerican Funding's net income for 2018 was $669 million, an increase of $95 million, or 17%, compared to 2017. In addition to the MidAmerican Energy impacts, MidAmerican Funding's net income for 2017 reflects after-tax charges of $17 million related to the tender offer of a portion of its 6.927% Senior Bonds due 2029.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as, electric utility margin and natural gas utility margin, to help evaluate results of operations. Electric utility margin is calculated as regulated electric operating revenue less cost of fuel and energy, which are captions presented on the Statements of Operations. Natural gas utility margin is calculated as regulated natural gas operating revenue less regulated cost of natural gas purchased for resale, which are included in regulated natural gas and other and cost of natural gas purchased for resale and other, respectively, on the Statements of Operations.

MidAmerican Energy's cost of fuel and energy and regulated cost of natural gas purchased for resale are generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in MidAmerican Energy's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes electric utility margin and natural gas utility margin more appropriately and concisely explains profitability rather than a discussion of revenue and cost of sales separately. Management believes the presentation of electric utility margin and natural gas utility margin provides meaningful and valuable insight into the information management considers important to running the business and a measure of comparability to others in the industry.

Electric utility margin and natural gas utility margin are not measures calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2019	2018	Change		2018	2017	Change	
Electric utility margin:								
Regulated electric operating revenue	$ 2,237	$ 2,283	$ (46)	(2)%	$ 2,283	$ 2,108	$ 175	8%
Cost of fuel and energy	399	487	(88)	(18)	487	434	53	12
Electric utility margin	1,838	1,796	42	2 %	1,796	1,674	122	7%
Natural gas utility margin:								
Regulated natural gas operating revenue	660	754	(94)	(12)%	754	719	35	5%
Cost of natural gas purchased for resale	395	465	(70)	(15)	465	441	24	5
Natural gas utility margin	265	289	(24)	(8)%	289	278	11	4%
Utility margin	$ 2,103	$ 2,085	$ 18	1 %	$ 2,085	$ 1,952	$ 133	7%
Other operating revenue	28	12	16	*	12	10	2	20%
Other cost of sales	18	1	17	*	1	1	—	—
Operations and maintenance	800	811	(11)	(1)	811	799	12	2
Depreciation and amortization	639	609	30	5	609	500	109	22
Property and other taxes	126	125	1	1	125	119	6	5
Operating income	$ 548	$ 551	$ (3)	(1)%	$ 551	$ 543	$ 8	1%

* Not meaningful.

Regulated Electric Utility Margin

A comparison of key operating results related to regulated electric utility margin is as follows for the years ended December 31:

	2019	2018	Change		2018	2017	Change	
Electric utility margin (in millions):								
Operating revenue	$ 2,237	$ 2,283	$ (46)	(2)%	$ 2,283	$ 2,108	$ 175	8%
Cost of fuel and energy	399	487	(88)	(18)	487	434	53	12
Electric utility margin	$ 1,838	$ 1,796	$ 42	2 %	$ 1,796	$ 1,674	$ 122	7%
Electricity sales (GWhs):								
Residential	6,575	6,763	(188)	(3)%	6,763	6,207	556	9%
Commercial	3,921	3,897	24	1	3,897	3,761	136	4
Industrial	14,127	13,587	540	4	13,587	12,957	630	5
Other	1,578	1,604	(26)	(2)	1,604	1,567	37	2
Total retail	26,201	25,851	350	1	25,851	24,492	1,359	6
Wholesale	10,000	11,181	(1,181)	(11)	11,181	9,165	2,016	22
Total sales	36,201	37,032	(831)	(2)%	37,032	33,657	3,375	10%
Average number of retail customers (in thousands)	786	780	6	1 %	780	770	10	1%
Average revenue per MWh:								
Retail	$ 74.01	$ 74.12	$ (0.11)	— %	$ 74.12	$ 73.88	$ 0.24	—%
Wholesale	$ 21.84	$ 25.63	$ (3.79)	(15)%	$ 25.63	$ 23.42	$ 2.21	9%
Heating degree days	6,661	6,627	34	1 %	6,627	5,492	1,135	21%
Cooling degree days	1,152	1,307	(155)	(12)%	1,307	1,117	190	17%
Sources of energy (GWhs)(1):								
Coal	12,182	15,811	(3,629)	(23)%	15,811	13,598	2,213	16%
Wind and other(2)	16,136	13,627	2,509	18	13,627	12,932	695	5
Nuclear	3,849	3,869	(20)	(1)	3,869	3,850	19	—
Natural gas	441	661	(220)	(33)	661	360	301	84
Total energy generated	32,608	33,968	(1,360)	(4)	33,968	30,740	3,228	11
Energy purchased	4,292	3,837	455	12	3,837	3,603	234	6
Total	36,900	37,805	(905)	(2)%	37,805	34,343	3,462	10%

(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 sources 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.

For 2019 compared to 2018, regulated electric utility margin increased $42 million primarily due to:

(1) Higher retail utility margin of $36 million due to -

- an increase of $73 million from non-weather-related sales growth due to higher industrial usage, partially offset by lower residential usage;
- an increase of $38 million, net of energy costs, from higher recoveries through bill riders, primarily related to the PTC component of the energy adjustment clause and ratemaking treatment for the impact of 2017 Tax Reform (both offset in income tax benefit), partially offset by a decrease of $49 million in electric energy efficiency program revenue (offset in operations and maintenance expense);
- a decrease of $3 million from various other revenue;
- a decrease of $18 million from the impact of weather; and
- a decrease of $54 million in averages revenue rates due to sales mix;

(2) Higher wholesale utility margin of $5 million due to higher margin per unit reflecting lower energy costs, partially offset by lower sales volumes; and

(3) Higher Multi-Value Projects ("MVP") transmission revenue of $1 million.

For 2018 compared to 2017, regulated electric utility margin increased $122 million primarily due to:

(1) Higher retail utility margin of $73 million due to -

- an increase of $104 million, net of energy costs, from higher recoveries through bill riders, primarily related to the PTC component of the energy adjustment clause (offset in income tax benefit);
- an increase of $58 million from non-weather-related sales growth due to higher industrial usage;
- an increase of $33 million from the impact of weather;
- an increase of $4 million from various other revenue; and
- a decrease of $126 million in averages rates, predominantly from the impact of a lower federal tax rate due to 2017 Tax Reform;

(2) Higher wholesale utility margin of $52 million due to higher margins per unit from higher market prices and lower fuel costs on higher sales volumes; and

(3) Lower MVP transmission revenue of $3 million due to refund accruals.

Regulated Natural Gas Utility Margin

A comparison of key operating results related to regulated natural gas utility margin is as follows for the years ended December 31:

	2019	2018	Change		2018	2017	Change	
Natural gas utility margin (in millions):								
Operating revenue	$ 660	$ 754	$ (94)	(12)%	$ 754	$ 719	$ 35	5 %
Cost of natural gas purchased for resale	395	465	(70)	(15)	465	441	24	5
Natural gas utility margin	$ 265	$ 289	$ (24)	(8)%	$ 289	$ 278	$ 11	4 %
Natural gas throughput (000's Dths):								
Residential	56,101	54,798	1,303	2 %	54,798	46,366	8,432	18 %
Commercial	27,333	26,382	951	4	26,382	23,434	2,948	13
Industrial	5,258	5,777	(519)	(9)	5,777	4,725	1,052	22
Other	77	48	29	60	48	38	10	26
Total retail sales	88,769	87,005	1,764	2	87,005	74,563	12,442	17
Wholesale sales	36,886	39,267	(2,381)	(6)	39,267	39,735	(468)	(1)
Total sales	125,655	126,272	(617)	—	126,272	114,298	11,974	10
Gas transportation service	112,143	102,198	9,945	10	102,198	92,136	10,062	11
Total natural gas throughput	237,798	228,470	9,328	4 %	228,470	206,434	22,036	11 %
Average number of retail customers (in thousands)	766	759	7	1 %	759	751	8	1 %
Average revenue per retail Dth sold	$ 6.03	$ 6.89	$ (0.86)	(12)%	$ 6.89	$ 7.64	$ (0.75)	(10)%
Average cost of natural gas per retail Dth sold	$ 3.47	$ 4.02	$ (0.55)	(14)%	$ 4.02	$ 4.41	$ (0.39)	(9)%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 3.14	$ 3.69	$ (0.55)	(15)%	$ 3.69	$ 3.86	$ (0.17)	(4)%
Heating degree days	6,980	6,843	137	2 %	6,843	5,788	1,055	18 %

For 2019 compared to 2018, regulated natural gas utility margin decreased $24 million primarily due to:

(1) A decrease of $27 million in natural gas energy efficiency program revenue (offset in operations and maintenance expense); and

(2) An increase of $2 million from higher retail sales volumes due primarily to the impact of colder winter temperatures.

For 2018 compared to 2017, regulated natural gas utility margin increased $11 million primarily due to:

(1) An increase of $16 million from higher retail sales volumes due primarily to the impact of colder winter temperatures;

(2) An increase of $2 million from higher natural gas transportation services; and

(3) A decrease of $9 million from rate and non-weather-related usage factors, including the impact of a lower federal tax rate due to 2017 Tax Reform.

Operating Expenses

MidAmerican Energy -

Operations and maintenance decreased $11 million for 2019 compared to 2018 due to lower energy efficiency program expense of $76 million (offset in operating revenue) and $9 million from lower fossil-fueled generation maintenance, partially offset by higher wind-powered generation costs of $37 million primarily due to new and repowered wind-powered generating facilities, higher natural gas and electric distribution operations costs of $11 million, higher transmission operations costs from MISO of $7 million (offset in operating revenue), and higher healthcare and other operations costs.

Operations and maintenance increased $12 million for 2018 compared to 2017 primarily due to higher wind-powered generation maintenance of $23 million from additional wind turbines, higher energy efficiency program expense of $6 million and higher transmission operations costs from MISO of $4 million, both of which are recoverable in bill riders and offset in operating revenue, partially offset by lower electric distribution and transmission maintenance of $13 million primarily from tree-trimming and emergency outage work and lower fossil-fueled and nuclear generation maintenance expense of $8 million.

Depreciation and amortization increased $30 million for 2019 compared to 2018 due to $78 million related to new and repowered wind-powered generating facilities and other plant placed in-service, partially offset by lower Iowa revenue sharing accruals of $46 million.

Depreciation and amortization increased $109 million for 2018 compared to 2017 primarily due to $67 million related to wind-powered generating facilities and other plant placed in-service and higher Iowa revenue sharing accruals of $44 million.

Property and other taxes increased $6 million for 2018 compared to 2017 due to higher wind turbine property taxes and other real estate taxes.

Other Income and (Expense)

MidAmerican Energy -

Interest expense increased $54 million for 2019 compared to 2018 primarily due to the issuance of first mortgage bonds totaling $1.5 billion in January 2019 and $850 million in October 2019, partially offset by the redemption of $500 million of first mortgage bonds in February 2019.

Interest expense increased $13 million for 2018 compared to 2017 primarily due to the issuance of $700 million of first mortgage bonds in February 2018 and $150 million of variable rate, tax-exempt bonds in December 2017, partially offset by the redemption of $350 million of senior notes in March 2018.

Allowance for borrowed and equity funds increased $32 million for 2019 compared to 2018 and $17 million for 2018 compared to 2017 primarily due to higher construction work-in-progress balances related to new and repowering wind-powered generation projects.

Other, net increased $20 million for 2019 compared to 2018 primarily due to higher returns on corporate-owned life insurance policies and higher interest income due to a favorable cash position.

Other, net decreased $7 million for 2018 compared to 2017 primarily due to lower returns on 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.

Income Tax Benefit

MidAmerican Energy -

MidAmerican Energy's income tax benefit increased $116 million for 2019 compared to 2018, and the effective tax rate was (88)% for 2019 and (60)% for 2018. The change in the effective tax rate was substantially due to an increase of $70 million in PTCs and the effects of ratemaking.

MidAmerican Energy's income tax benefit increased $72 million for 2018 compared to 2017, and the effective tax rate was (60)% for 2018 and (43)% for 2017. The change in the effective tax rate was substantially due to the reduction in the United States federal corporate income tax rate from 35% to 21%, effective January 1, 2018, an increase of $21 million in PTCs and the effects of ratemaking.

Federal renewable electricity PTCs 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 for earning the credits. Most of those facilities have since been repowered, and under Internal Revenue Service rules, qualifying repowered facilities are eligible for the credits, or a portion thereof, for 10 years from the date they are returned to service. Refer to "Capital Expenditures" in Liquidity and Capital Resources for additional information about repowering and new wind-powered generation placed in-service. A credit per kilowatt hour of $0.025 for 2019 and $0.024 for 2018 and 2017 was applied to the annual production of eligible facilities, which resulted in $378 million, $308 million and $287 million, respectively, in PTCs.

MidAmerican Funding -

MidAmerican Funding's income tax benefit increased $115 million for 2019 compared to 2018, and the effective tax rate was (93)% for 2019 and (64)% for 2018. MidAmerican Funding's income tax benefit increased $60 million for 2018 compared to 2017, and the effective tax rate was (64)% for 2018 and (54)% for 2017. 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.

Liquidity and Capital Resources

As of December 31, 2019, MidAmerican Energy's and MidAmerican Funding's total net liquidity were as follows (in millions):

MidAmerican Energy:	
Cash and cash equivalents	$ 287
Credit facilities, maturing 2020 and 2022	1,305
Less:	
Tax-exempt bond support	(370)
Net credit facilities	935
MidAmerican Energy total net liquidity	$ 1,222
MidAmerican Funding:	
MidAmerican Energy total net liquidity	$ 1,222
Cash and cash equivalents	1
MHC, Inc. credit facility, maturing 2020	4
MidAmerican Funding total net liquidity	$ 1,227

Operating Activities

MidAmerican Energy's net cash flows from operating activities were $1,490 million, $1,508 million and $1,396 million for 2019, 2018 and 2017, respectively. MidAmerican Funding's net cash flows from operating activities were $1,475 million, $1,516 million and $1,380 million for 2019, 2018 and 2017, respectively. Cash flows from operating activities decreased for 2019 compared to 2018 primarily due to lower income tax receipts and higher interest payments, partially offset by lower payments to vendors and lower payments for the settlement of asset retirement obligations. Cash flows from operating activities increased for 2018 compared to 2017 primarily due to higher cash margins for MidAmerican Energy's regulated electric and natural gas businesses, higher income tax receipts and higher energy efficiency cost recovery cash inflows.

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.

Investing Activities

MidAmerican Energy's net cash flows from investing activities were $(2,801) million, $(2,310) million and $(1,776) million for 2019, 2018 and 2017, respectively. MidAmerican Funding's net cash flows from investing activities were $(2,801) million, $(2,310) million and $(1,779) million for 2019, 2018 and 2017, respectively. Net cash flows from investing activities consist almost entirely of capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures. Purchases and proceeds related to marketable securities primarily consist of activity within the Quad Cities Generating Station nuclear decommissioning trust, and other investment proceeds relates primarily to company-owned life insurance policies. In 2018, proceeds from sales of other investments includes $15 million for the transfer of corporate aircraft to BHE.

Financing Activities

MidAmerican Energy's net cash flows from financing activities were $1.585 billion, $576 million and $636 million for 2019, 2018 and 2017, respectively. MidAmerican Funding's net cash flows from financing activities were $1.6 billion, $569 million and $654 million for 2019, 2018 and 2017, respectively. In January 2019, MidAmerican Energy issued $600 million of its 3.65% First Mortgage Bonds due April 2029 and $900 million of its 4.25% First Mortgage Bonds due July 2049, and in October 2019, issued an additional $250 million of its 3.65% First Mortgage Bonds due April 2029 and $600 million of its 3.15% First Mortgage Bonds due April 2050. In February 2019, MidAmerican Energy redeemed $500 million of its 2.40% First Mortgage Bonds due in March 2019 at a redemption price of 100% of the principal amount plus accrued interest. In February 2018, MidAmerican Energy issued $700 million of its 3.65% First Mortgage Bonds due August 2048 and, in March 2018, repaid $350 million of its 5.30% Senior Notes due March 2018. 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. In February 2017, MidAmerican Energy redeemed in full through optional redemption its $250 million of 5.95% Senior Notes due July 2017. Net (repayments of) proceeds from short-term debt relate to MidAmerican Energy's use of short-term borrowings through its commercial paper program.

In December 2017, MidAmerican Funding redeemed through a tender offer a portion of its 6.927% Senior Bonds. MidAmerican Funding received $15 million and $133 million in 2019 and 2017, respectively, and made payments totaling $8 million in 2018 through its note payable with BHE.

Debt Authorizations and Related Matters

MidAmerican Energy has authority from the FERC to issue through July 31, 2020, commercial paper and bank notes aggregating $1.3 billion 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 2022. 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. MidAmerican Energy has a $400 million unsecured credit facility, which expires in August 2020 and has a variable interest rate based on the Eurodollar rate or a base rate, at MidAmerican Energy's option, plus a spread. Additionally, MidAmerican Energy has a $5 million unsecured credit facility for general corporate purposes.

MidAmerican Energy currently has an effective automatic registration statement with the SEC to issue an indeterminate amount of long-term debt securities through June 26, 2021. Additionally, MidAmerican Energy has authorization from the FERC to issue, through June 30, 2021, long-term debt securities up to an aggregate of $850 million at interest rates not to exceed the applicable United States Treasury rate plus a spread of 175 basis points and preferred stock up to an aggregate of $500 million and from the ICC to issue long-term debt securities up to an aggregate of $850 million through August 20, 2022, and preferred stock up to an aggregate of $500 million through November 1, 2020.

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 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, impacts to customers' rates; changes in environmental and other rules and regulations; 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		
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Wind-powered generation under ratemaking principles	$ 657	$ 1,261	$ 1,486	$ 371	$ —	$ —
Renewable generation not under ratemaking principles	—	—	—	420	—	—
Wind-powered generation repowering	514	422	369	136	436	329
Other	602	649	955	934	591	548
Total	$ 1,773	$ 2,332	$ 2,810	$ 1,861	$ 1,027	$ 877

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 1,019 MWs (nominal ratings) during 2019, 817 MWs (nominal ratings) during 2018 and 334 MWs (nominal ratings) during 2017. Wind XI, a 2,000-MW project, was completed in January 2020. Wind XII is a 591-MW project, including 201 MWs placed in-service in 2019 and facilities expected to be placed in-service by the end of 2020. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for 100% of PTCs available. PTCs from these projects are excluded from MidAmerican Energy's Iowa energy adjustment clause until these generation assets are reflected in base rates.

  Additionally, MidAmerican Energy continues to evaluate wind-powered and other renewable generating facilities that would not be subject to pre-approved ratemaking principles.

- The repowering of the oldest of MidAmerican Energy's wind-powered generating facilities in Iowa. IRS rules provide for re-establishment of the PTC for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement meets IRS guidelines, PTCs are re-established for ten years at rates that depend upon the date in which construction begins. Under MidAmerican Energy's Iowa electric tariff, federal PTCs 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 PTCs related to these repowered facilities. Below is a summary of historical and forecast wind-powered generation repowering projects:

Year Placed In-Service	Capacity (MWs)[1]	% of Federal Production Tax Credit Rate
Historical:		
2017	414	100%
2018	222	100%
2019	466	100%
2019	120	80%
Forecast:		
2020	55	80%
2021	594	80%
2022	407	60%

(1) Capacity values for historical repowered facilities reflect new nominal ratings and for forecast projects reflect existing nominal ratings.

- 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, 2019 (in millions):

	Payments Due By Periods				
	2020	2021-2022	2023-2024	2025 and After	Total
MidAmerican Energy:					
Long-term debt	$ —	$ 1	$ 850	$ 6,425	$ 7,276
Interest payments on long-term debt[1][2]	294	590	580	4,447	5,911
Coal, electricity and natural gas contracts commitments[1]	244	246	86	52	628
Construction commitments[1]	670	542	6	—	1,218
Easements[1]	32	73	77	1,492	1,674
Other commitments[1]	198	310	275	432	1,215
	1,438	1,762	1,874	12,848	17,922
MidAmerican Funding parent:					
Long-term debt	—	—	—	239	239
Interest payments on long-term debt[1]	17	33	33	75	158
	17	33	33	314	397
Total contractual cash obligations	$ 1,455	$ 1,795	$ 1,907	$ 13,162	$ 18,319

(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, 2019 rates.

MidAmerican Energy has other types of commitments that relate primarily to construction expenditures (in "Capital Expenditures" section above) and asset retirement obligations beyond 2019 (Note 11), which have not been included in the above table because the amount or timing of the cash payments is not certain. Refer to Notes 8, 11 and 13 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. 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. 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 United States Constitution. Both lawsuits were dismissed at the Northern District of Illinois, and the United States Court of Appeals for the Seventh Circuit affirmed the dismissals. On April 15, 2019, plaintiffs' petition seeking United States Supreme Court review of the case was denied.

On January 9, 2017, the Electric Power Supply Association ("EPSA") 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. When a resource is subjected to a MOPR, its offer price in the market is adjusted to effectively remove the revenues it receives through a government-provided financial support program, resulting in a higher offer that may not clear the capacity market. If the EPSA's requests are 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 filed protests at the FERC in response to each filing.

On December 19, 2019, the FERC issued an order in the PJM Interconnection, L.L.C. ("PJM") MOPR proceeding that broadly applies the MOPR to all new and existing resources, including nuclear, greatly expanding the breadth and scope of PJM's MOPR, effective as of PJM's next capacity auction. The FERC directed PJM to make a compliance filing within 90 days. The FERC has no deadline for acting on PJM's compliance filing. While the FERC included some limited exemptions in its order, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. In addition, the FERC provided no new mechanism for accommodating state-supported resources other than the existing Fixed Resource Requirement ("FRR") mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. Unless Illinois can implement an FRR program in their PJM zones, the MOPR will apply to Exelon Generation's nuclear plants in those states receiving a benefit under the Illinois zero emissions program, including Quad Cities Station, resulting in higher offers for those units that may not clear the capacity market.

On January 21, 2020, Exelon Generation, PJM and a number of other entities submitted individual requests for rehearing of the FERC's December 19, 2019 order on the PJM MOPR. Exelon Generation is currently working with PJM and other stakeholders to pursue the FRR option prior to the next capacity auction in PJM. If Illinois implements the FRR option, Quad Cities Station could be removed from PJM's capacity auction and instead supply capacity and be compensated under the FRR program. Implementing the FRR program in Illinois will require both legislative and regulatory changes. MidAmerican Energy cannot predict whether such legislative and regulatory changes can be implemented prior to the next capacity auction in PJM or their potential impact on the continued operation of Quad Cities Station.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding climate change, RPS, air and water quality, emissions performance standards, 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.

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, 2019, MidAmerican Energy's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the three recognized credit rating agencies were investment grade. As a result of the issuance of first mortgage bonds by MidAmerican Energy in September 2013, its then outstanding senior unsecured debt was equally and ratably secured with such first mortgage bonds. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's first mortgage bonds.

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

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base MidAmerican Energy's collateral requirements on its credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2019, MidAmerican Energy would have been required to post $84 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.

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 $289 million and total regulatory liabilities were $1,406 million as of December 31, 2019. Refer to Note 5 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory assets and liabilities.

Income Taxes

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory commissions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of their federal, state and local tax examinations is uncertain, each company believes it has made adequate provisions for its income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on its consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2019, 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, 2019. 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, 2019, MidAmerican Energy recognized a net liability totaling $- million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2019, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled $26 million and $32 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 10 of Notes to Financial Statements in Item 8 of this Form 10-K for disclosures about MidAmerican Energy's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2019.

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

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

MidAmerican Energy chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5% by 2025 at which point the rate of increase is assumed to remain constant. Refer to Note 10 of Notes to Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

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

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2019 Benefit Obligations:				
Discount rate	$ (34)	$ 37	$ (8)	$ 9
Effect on 2019 Periodic Cost:				
Discount rate	2	(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 $91 million as of December 31, 2019. 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 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 Note 2 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.

Interest Rate Risk

MidAmerican Energy and MidAmerican Funding are exposed to interest rate risk on their outstanding variable-rate short- and long-term debt and future debt issuances. MidAmerican Energy and MidAmerican Funding manage interest rate risk by limiting their exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the fixed-rate long-term debt does not expose MidAmerican Energy or MidAmerican Funding to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if MidAmerican Energy or MidAmerican Funding were to reacquire all or a portion of these instruments prior to their maturity. MidAmerican Energy or MidAmerican Funding may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate their exposure to interest rate risk. The nature and amount of their short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7, 8 and 12 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, 2019 and 2018, MidAmerican Energy had short- and long-term variable-rate obligations totaling $370 million and $610 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, 2019, 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, 2019 and 2018.

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, 2019, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

MidAmerican Energy Company

MidAmerican Funding, LLC and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MidAmerican Energy Company
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying balance sheets of MidAmerican Energy Company ("MidAmerican Energy") as of December 31, 2019 and 2018, the related statements of operations, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2019, and the related notes and the schedule listed in the Index at Item 15(a)(2) (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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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 21, 2020

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 287	$ —
Trade receivables, net	291	367
Inventories	226	204
Other current assets	90	90
Total current assets	894	661
Property, plant and equipment, net	18,375	16,157
Regulatory assets	289	273
Investments and restricted investments	818	708
Other assets	188	121
Total assets	$ 20,564	$ 17,920

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

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2019	2018
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 519	$ 575
Accrued interest	78	53
Accrued property, income and other taxes	225	300
Short-term debt	—	240
Current portion of long-term debt	—	500
Other current liabilities	219	122
Total current liabilities	1,041	1,790
Long-term debt	7,208	4,879
Regulatory liabilities	1,406	1,620
Deferred income taxes	2,626	2,322
Asset retirement obligations	704	552
Other long-term liabilities	339	311
Total liabilities	13,324	11,474
Commitments and contingencies (Note 13)		
Shareholder's equity:		
Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding	—	—
Additional paid-in capital	561	561
Retained earnings	6,679	5,885
Total shareholder's equity	7,240	6,446
Total liabilities and shareholder's equity	$ 20,564	$ 17,920

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Operating revenue:			
Regulated electric	$ 2,237	$ 2,283	$ 2,108
Regulated natural gas and other	688	766	729
Total operating revenue	2,925	3,049	2,837
Operating expenses:			
Cost of fuel and energy	399	487	434
Cost of natural gas purchased for resale and other	413	466	442
Operations and maintenance	800	811	799
Depreciation and amortization	639	609	500
Property and other taxes	126	125	119
Total operating expenses	2,377	2,498	2,294
Operating income	548	551	543
Other income (expense):			
Interest expense	(281)	(227)	(214)
Allowance for borrowed funds	27	20	15
Allowance for equity funds	78	53	41
Other, net	50	30	37
Total other income (expense)	(126)	(124)	(121)
Income before income tax benefit	422	427	422
Income tax benefit	(371)	(255)	(183)
Net income	$ 793	$ 682	$ 605

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Total Shareholder's Equity
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
Net income	—	—	682	682
Balance, December 31, 2018	—	561	5,885	6,446
Net income	—	—	793	793
Other equity transactions	—	—	1	1
Balance, December 31, 2019	$ —	$ 561	$ 6,679	$ 7,240

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,		
	2019	**2018**	**2017**
Cash flows from operating activities:			
Net income	$ 793	$ 682	$ 605
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	639	609	500
Amortization of utility plant to other operating expenses	33	34	34
Allowance for equity funds	(78)	(53)	(41)
Deferred income taxes and amortization of investment tax credits	154	33	332
Other, net	(9)	13	(15)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	60	(25)	(60)
Inventories	(22)	41	19
Derivative collateral, net	(1)	(1)	2
Contributions to pension and other postretirement benefit plans, net	(10)	(13)	(11)
Accrued property, income and other taxes, net	(76)	218	(41)
Accounts payable and other liabilities	7	(30)	72
Net cash flows from operating activities	1,490	1,508	1,396
Cash flows from investing activities:			
Capital expenditures	(2,810)	(2,332)	(1,773)
Purchases of marketable securities	(156)	(263)	(143)
Proceeds from sales of marketable securities	138	223	137
Proceeds from sales of other investments	1	17	2
Other investment proceeds	13	15	1
Other, net	13	30	—
Net cash flows from investing activities	(2,801)	(2,310)	(1,776)
Cash flows from financing activities:			
Proceeds from long-term debt	2,326	687	990
Repayments of long-term debt	(500)	(350)	(255)
Net (repayments of) proceeds from short-term debt	(240)	240	(99)
Other, net	(1)	(1)	—
Net cash flows from financing activities	1,585	576	636
Net change in cash and cash equivalents and restricted cash and cash equivalents	274	(226)	256
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	56	282	26
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 330	$ 56	$ 282

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

MIDAMERICAN ENERGY COMPANY
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

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 subsidiary is Midwest Capital Group, Inc. 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 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 Presentation

The Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2019, 2018 and 2017.

Use of Estimates in Preparation of Financial Statements

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

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Board ("IUB"), the Illinois Commerce Commission ("ICC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). MidAmerican Energy's accounting policies and the accompanying Financial Statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Cash Equivalents 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 cash and cash equivalents consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax exempt bond agreements. Restricted amounts are included in other current assets and investments and restricted investments on the Balance Sheets.

Investments

Fixed Maturity Securities

MidAmerican Energy's management determines the appropriate classification of investments in fixed maturity 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 investments 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 fixed maturity 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 refund to customers any decommissioning funds in excess of costs for these activities through regulated rates. Trading investments are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The difference between the original cost and maturity value of a fixed maturity security is amortized to earnings using the interest method.

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired with respect to securities classified as available-for-sale. If the value of a fixed maturity investment declines to below amortized cost and the decline is deemed other than temporary, the amortized cost of the investment is reduced to fair value, with a corresponding charge to earnings. 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.

Equity Securities

All changes in fair value of equity securities in a trust related to the decommissioning of nuclear generation assets are recorded as a net regulatory liability since MidAmerican Energy expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates.

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 collectability 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, 2019 and 2018, the allowance for doubtful accounts totaled $5 million and $7 million, respectively, and is included in receivables, net on the Balance Sheets.

Derivatives

MidAmerican Energy employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities, and interest rate risk. Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked to market, and settled amounts are recognized as operating revenue or cost of sales on the Statements of Operations.

For MidAmerican Energy's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities.

Inventories

Inventories consist mainly of coal stocks, totaling $66 million and $51 million as of December 31, 2019 and 2018, respectively, materials and supplies, totaling $128 million and $124 million as of December 31, 2019 and 2018, respectively, and natural gas in storage, totaling $28 million and $24 million as of December 31, 2019 and 2018, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined using the average cost method. The cost of stored natural gas is determined using the last-in-first-out method. With respect to stored natural gas, the replacement cost would be $2 million lower and $14 million higher as of December 31, 2019 and 2018, respectively.

Property, Plant and Equipment, 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 retail 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

MidAmerican Energy uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which MidAmerican Energy expects to be entitled in exchange for those goods and services. MidAmerican Energy records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statements of Operations.

A majority of MidAmerican Energy's energy revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

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, 2019 and 2018, unbilled revenue was $91 million and $88 million, respectively, and is included in trade 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 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 natural 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 natural 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, 2019 and 2018, was $56 million.

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 and Iowa state income tax returns. 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 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 commissions.

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 commissions. 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 February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("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 on 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. Following the issuance of ASU No. 2016-02, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2016-02 but did not change the core principle of the guidance. MidAmerican Energy has elected to utilize various practical expedients available to adopt ASU No. 2016-02, including (1) the package of three not requiring a reassessment of (i) whether any expired or existing contracts are or contain leases; (ii) the lease classification for any expired or existing leases; and (iii) initial direct costs for any existing leases; (2) using hindsight in determining the lease term; and (3) not requiring a reassessment of whether existing or expired land easements that were not previously accounted for as leases under ASC Topic 840 are or contain a lease under ASC Topic 842. MidAmerican Energy adopted this guidance for all applicable contracts in effect as of January 1, 2019 under a modified retrospective method, and the adoption did not have a cumulative effect impact at the date of initial adoption nor a material impact on MidAmerican Energy's Financial Statements and disclosures included within Notes to Financial Statements.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2019	2018
Utility plant in service:			
Generation	20-70 years	$ 15,687	$ 13,727
Transmission	52-75 years	2,124	1,934
Electric distribution	20-75 years	4,095	3,672
Natural gas distribution	29-75 years	1,820	1,724
Utility plant in service		23,726	21,057
Accumulated depreciation and amortization		(6,139)	(5,941)
Utility plant in service, net		17,587	15,116
Nonregulated property, net:			
Nonregulated property gross	20-50 years	7	7
Accumulated depreciation and amortization		(1)	(1)
Nonregulated property, net		6	6
		17,593	15,122
Construction work-in-progress		782	1,035
Property, plant and equipment, net		$ 18,375	$ 16,157

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:

	2019	2018	2017
Electric	3.1%	2.9%	2.6%
Natural gas	2.8%	2.8%	2.7%

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, MidAmerican Energy, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. MidAmerican Energy accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating 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, 2019 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa Unit No. 1	88%	$ 834	$ 458	$ 7
Quad Cities Unit Nos. 1 & 2[(1)]	25	729	424	11
Walter Scott, Jr. Unit No. 3	79	930	392	5
Walter Scott, Jr. Unit No. 4[(2)]	60	316	131	1
George Neal Unit No. 4	41	316	171	2
Ottumwa Unit No. 1	52	634	229	19
George Neal Unit No. 3	72	489	238	4
Transmission facilities	Various	258	95	—
Total		$ 4,506	$ 2,138	$ 49

(1) Includes amounts related to nuclear fuel.

(2) Plant in service and accumulated depreciation and amortization amounts are net of credits applied under Iowa regulatory arrangements totaling $458 million and $94 million, respectively.

(5) Regulatory Matters

Regulatory Assets

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	2019	2018
Asset retirement obligations[(1)]	6 years	$ 223	$ 160
Employee benefit plans[(2)]	12 years	26	62
Unrealized loss on regulated derivative contracts	1 year	7	19
Other	Various	33	32
Total		$ 289	$ 273

(1) Amount predominantly relates to asset retirement obligations for fossil-fueled and wind-powered generating facilities. Refer to Note 11 for a discussion of asset retirement obligations.

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

MidAmerican Energy had regulatory assets not earning a return on investment of $286 million and $269 million as of December 31, 2019 and 2018, respectively.

Regulatory Liabilities

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	2019	2018
Cost of removal accrual[1]	29 years	$ 572	$ 708
Deferred income taxes[2]	Various	478	626
Asset retirement obligations[3]	33 years	241	160
Employee benefit plans[4]	10 years	32	—
Pre-funded AFUDC on transmission MVPs[5]	53 years	35	36
Iowa electric revenue sharing accrual[6]	1 year	22	70
Other	Various	26	20
Total		$ 1,406	$ 1,620

(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 primarily 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.

(3) Amount represents the excess of nuclear decommission trust assets over the related asset retirement obligation. Refer to Note 11 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.

(6) Investments and Restricted Investments

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

	2019	2018
Nuclear decommissioning trust	$ 599	$ 504
Rabbi trusts	203	191
Other	16	13
Total	$ 818	$ 708

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. The debt and equity securities in the trust 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, 2019 and 2018, the fair value of the trust's funds was invested as follows: 56% and 51%, respectively, in domestic common equity securities, 31% and 37%, respectively, in United States government securities, 10% and 9%, 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 (expense) - other, net on the Statements of Operation.

(7) Short-Term Debt and Credit Facilities

Interim financing of working capital needs and the construction program is obtained from unaffiliated parties through the sale of commercial paper or short-term borrowing from banks. MidAmerican Energy has a $900 million unsecured credit facility expiring June 2022. The credit facility supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations, provides for the issuance of letters of credit and 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. MidAmerican Energy has a $400 million unsecured credit facility that expires in August 2020 and has a variable interest rate based on the Eurodollar rate or a base rate, at MidAmerican Energy's option, plus a spread. Additionally, MidAmerican Energy has a $5 million unsecured credit facility, which expires in June 2020 and has a variable interest rate based on the Eurodollar rate plus a spread. As of December 31, 2018, MidAmerican Energy had a $400 million unsecured credit facility expiring November 2019, which was terminated in January 2019. MidAmerican Energy had commercial paper borrowings outstanding of $- million as of December 31, 2019, and $240 million with a weighted average interest rate of 2.49% as of December 31, 2018. The $900 million and $400 million credit facilities each require 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, 2019, 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 $1.3 billion through July 31, 2020.

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

	2019	2018
Credit facilities	$ 1,305	$ 1,305
Less:		
Short-term debt outstanding	—	(240)
Variable-rate tax-exempt bond support	(370)	(370)
Net credit facilities	$ 935	$ 695

(8) Long-Term Debt

MidAmerican Energy's long-term debt consists of the following, including amounts maturing within one year and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2019	2018
First mortgage bonds:			
2.40%, due 2019	$ —	$ —	$ 500
3.70%, due 2023	250	249	249
3.50%, due 2024	500	501	500
3.10%, due 2027	375	373	372
3.65%, due 2029	850	864	—
4.80%, due 2043	350	346	346
4.40%, due 2044	400	395	395
4.25%, due 2046	450	445	445
3.95%, due 2047	475	470	470
3.65%, due 2048	700	688	688
4.25%, due 2049	900	872	—
3.15%, due 2050	600	591	—
Notes:			
6.75% Series, due 2031	400	396	396
5.75% Series, due 2035	300	298	298
5.8% Series, due 2036	350	348	347
Transmission upgrade obligation, 4.45% and 3.42% due through 2035 and 2036, respectively	6	4	5
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2019-1.66%, 2018-1.74%):			
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	149
Total	$ 7,276	$ 7,208	$ 5,379

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2020, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2020	$ —
2021	—
2022	1
2023	315
2024	535
2025 and thereafter	6,425

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, 2019, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $20 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, 2019 and 2018. 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. Proceeds of the $150 million of variable-rate, tax-exempt Solid Waste Facilities Revenue Bonds due December 2047 are restricted for the purpose of constructing solid waste facilities. As of December 31, 2019, $32 million of the restricted proceeds remain and are reflected in other current assets on the Balance Sheet.

As of December 31, 2019, 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, 2019, MidAmerican Energy's common equity ratio was 51% 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 $2.0 billion as of December 31, 2019, without falling below 42%.

(9) Income Taxes

MidAmerican Energy's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2019	2018	2017
Current:			
Federal	$ (478)	$ (276)	$ (490)
State	(47)	(12)	(25)
	(525)	(288)	(515)
Deferred:			
Federal	166	42	335
State	(11)	(8)	(2)
	155	34	333
Investment tax credits	(1)	(1)	(1)
Total	$ (371)	$ (255)	$ (183)

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:

	2019	2018	2017
Federal statutory income tax rate	21 %	21 %	35 %
Income tax credits	(90)	(73)	(68)
State income tax, net of federal income tax benefit	(11)	(4)	(4)
Effects of ratemaking	(8)	(5)	(7)
Other, net	—	1	1
Effective income tax rate	(88)%	(60)%	(43)%

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

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 368	$ 405
Asset retirement obligations	234	164
Employee benefits	26	47
Other	71	80
Total deferred income tax assets	699	696
Deferred income tax liabilities:		
Depreciable property	(3,253)	(2,945)
Regulatory assets	(68)	(61)
Other	(4)	(12)
Total deferred income tax liabilities	(3,325)	(3,018)
Net deferred income tax liability	$ (2,626)	$ (2,322)

As of December 31, 2019, MidAmerican Energy has available $51 million of state tax carryforwards, principally related to $745 million of net operating losses, that expire at various intervals between 2020 and 2038.

The United States Internal Revenue Service has closed its examination of MidAmerican Energy's income tax returns through December 31, 2011. The statute of limitations for MidAmerican Energy's state income tax returns have expired through December 31, 2009, with the exception of Iowa and Illinois, for which the statute of limitations have expired through December 31, 2015, except for the impact of any federal audit adjustments. 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 statute of limitations is not closed.

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):

	2019	2018
Beginning balance	$ 10	$ 12
Additions based on tax positions related to the current year	5	4
Additions for tax positions of prior years	10	47
Reductions based on tax positions related to the current year	(5)	(4)
Reductions for tax positions of prior years	(12)	(48)
Interest and penalties	—	(1)
Ending balance	$ 8	$ 10

As of December 31, 2019, MidAmerican Energy had unrecognized tax benefits totaling $27 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Energy's effective income tax rate.

(10) Employee Benefit Plans

Defined Benefit Plan

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. In 2018, the defined benefit pension plan recorded a settlement gain of $1 million for previously unrecognized gains as a result of excess lump sum distributions over the defined threshold for the year ended December 31, 2018.

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 2019, 2018 and 2017, MidAmerican Energy's share of the pension net periodic benefit (credit) cost was $(8) million, $(9) million and $(6) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit (credit) cost in 2019, 2018 and 2017 totaled $1 million, $(2) million and $(1) million, respectively.

Net periodic benefit cost for the plans of MidAmerican Energy and the aforementioned affiliates included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2019	2018	2017	2019	2018	2017
Service cost	$ 6	$ 9	$ 9	$ 5	$ 5	$ 5
Interest cost	30	28	31	10	8	9
Expected return on plan assets	(41)	(44)	(44)	(13)	(13)	(14)
Settlement	—	(1)	—	—	—	—
Net amortization	1	2	2	(3)	(4)	(4)
Net periodic benefit (credit) cost	$ (4)	$ (6)	$ (2)	$ (1)	$ (4)	$ (4)

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	
	2019	2018	2019	2018
Plan assets at fair value, beginning of year	$ 644	$ 745	$ 247	$ 277
Employer contributions	7	7	1	1
Participant contributions	—	—	2	1
Actual return on plan assets	123	(39)	42	(17)
Settlement	—	(37)	—	—
Benefits paid	(57)	(32)	(20)	(15)
Plan assets at fair value, end of year	$ 717	$ 644	$ 272	$ 247

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

	Pension		Other Postretirement	
	2019	2018	2019	2018
Benefit obligation, beginning of year	$ 736	$ 799	$ 242	$ 246
Service cost	6	9	5	5
Interest cost	30	28	10	8
Participant contributions	—	—	2	1
Actuarial (gain) loss	48	(33)	(13)	(3)
Plan amendments	—	2	—	—
Settlement	—	(37)	—	—
Benefits paid	(57)	(32)	(20)	(15)
Benefit obligation, end of year	$ 763	$ 736	$ 226	$ 242
Accumulated benefit obligation, end of year	$ 758	$ 733		

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	
	2019	2018	2019	2018
Plan assets at fair value, end of year	$ 717	$ 644	$ 272	$ 247
Less - Benefit obligation, end of year	763	736	226	242
Funded status	$ (46)	$ (92)	$ 46	$ 5
Amounts recognized on the Balance Sheets:				
Other assets	$ 66	$ 17	$ 46	$ 5
Other current liabilities	(7)	(7)	—	—
Other liabilities	(105)	(102)	—	—
Amounts recognized	$ (46)	$ (92)	$ 46	$ 5

The SERP has no plan assets; however, MidAmerican Energy and BHE have Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in MidAmerican Energy's Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $122 million and $116 million as of December 31, 2019 and 2018. These assets are not included in the plan assets in the above table, but are reflected in investments and restricted investments on the Balance Sheets. The accumulated benefit obligation and projected benefit obligation for the SERP was $112 million and $112 million for 2019 and $109 million and $109 million for 2018, respectively.

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	
	2019	2018	2019	2018
Net loss (gain)	$ 6	$ 40	$ 4	$ 48
Prior service cost (credit)	(1)	1	(14)	(20)
Total	$ 5	$ 41	$ (10)	$ 28

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, 2019 and 2018 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2017	$ 24	$ (41)	$ 7	$ (10)
Net loss arising during the year	2	41	9	52
Net amortization	(2)	—	—	(2)
Settlement	1	—	—	1
Total	1	41	9	51
Balance, December 31, 2018	25	—	16	41
Net (gain) loss arising during the year	(5)	(32)	2	(35)
Net amortization	(1)	—	—	(1)
Total	(6)	(32)	2	(36)
Balance, December 31, 2019	$ 19	$ (32)	$ 18	$ 5

	Regulatory Asset	Receivables (Payables) with Affiliates	Total
Other Postretirement			
Balance, December 31, 2017	$ 14	$ (16)	$ (2)
Net loss arising during the year	20	6	26
Net amortization	3	1	4
Total	23	7	30
Balance, December 31, 2018	37	(9)	28
Net (gain) arising during the year	(33)	(9)	(42)
Net amortization	3	1	4
Total	(30)	(8)	(38)
Balance, December 31, 2019	$ 7	$ (17)	$ (10)

Actuarial gains for 2019 impacting the December 31, 2019 funded status for the pension and other postretirement plans are due to higher than assumed actual return on plan assets, offset by a decrease in the discount rate assumptions from that assumed at December 31, 2018.

Plan Assumptions

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

	Pension			Other Postretirement		
	2019	2018	2017	2019	2018	2017
Benefit obligations as of December 31:						
Discount rate	3.40%	4.25%	3.60%	3.20%	4.15%	3.50%
Rate of compensation increase	2.75%	2.75%	2.75%	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2017	N/A	N/A	1.44%	N/A	N/A	N/A
2018	N/A	2.26%	2.26%	N/A	N/A	N/A
2019	3.40%	3.40%	2.26%	N/A	N/A	N/A
2020	2.27%	3.40%	1.60%	N/A	N/A	N/A
2021	2.27%	3.40%	1.60%	N/A	N/A	N/A
2022 and beyond	2.27%	3.40%	1.60%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.25%	3.60%	4.10%	4.15%	3.50%	3.90%
Expected return on plan assets[(1)]	6.50%	6.50%	6.75%	6.25%	6.25%	6.50%
Rate of compensation increase	2.75%	2.75%	2.75%	N/A	N/A	N/A
Interest crediting rates for cash balance plan	3.40%	2.26%	1.44%	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 4.62% for 2019, 4.13% for 2018, and 4.81% for 2017.

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.

	2019	2018
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.50%	6.80%
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

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $7 million and $1 million, respectively, during 2020. Funding to MidAmerican Energy's qualified 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 evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plans.

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 2020 through 2024 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2020	$ 64	$ 20
2021	63	22
2022	61	22
2023	58	21
2024	56	20
2025-2029	244	84

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, 2019:

	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, 2019:				
Cash equivalents	$ 21	$ —	$ —	$ 21
Debt securities:				
United States government obligations	16	—	—	16
Corporate obligations	—	61	—	61
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	33	—	33
Equity securities:				
United States companies	129	—	—	129
International companies	42	—	—	42
Investment funds[2]	69	—	—	69
Total assets in the hierarchy	$ 277	$ 99	$ —	376
Investment funds[2] measured at net asset value				299
Real estate funds measured at net asset value				42
Total assets measured at fair value				$ 717
As of December 31, 2018:				
Cash equivalents	$ —	$ 20	$ —	$ 20
Debt securities:				
United States government obligations	6	—	—	6
Corporate obligations	—	63	—	63
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	111	—	—	111
International companies	35	—	—	35
Investment funds[2]	65	—	—	65
Total assets in the hierarchy	$ 217	$ 126	$ —	343
Investment funds[2] measured at net asset value				260
Real estate funds measured at net asset value				41
Total assets measured at fair value				$ 644

(1) Refer to Note 12 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 2019 and 65% and 35%, respectively, for 2018. Additionally, these funds are invested in United States and international securities of approximately 74% and 26%, respectively, for 2019 and 74% and 26%, respectively, for 2018.

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, 2019:				
Cash equivalents	$ 6	$ —	$ —	$ 6
Debt securities:				
United States government obligations	6	—	—	6
Corporate obligations	—	12	—	12
Municipal obligations	—	55	—	55
Agency, asset and mortgage-backed obligations	—	10	—	10
Equity securities:				
United States companies	75	—	—	75
Investment funds(2)	108	—	—	108
Total assets measured at fair value	$ 195	$ 77	$ —	$ 272
As of December 31, 2018:				
Cash equivalents	$ 5	$ —	$ —	$ 5
Debt securities:				
United States government obligations	6	—	—	6
Corporate obligations	—	12	—	12
Municipal obligations	—	43	—	43
Agency, asset and mortgage-backed obligations	—	12	—	12
Equity securities:				
United States companies	73	—	—	73
Investment funds(2)	96	—	—	96
Total assets measured at fair value	$ 180	$ 67	$ —	$ 247

(1) Refer to Note 12 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 77% and 23%, respectively, for 2019 and 78% and 22%, respectively, for 2018. Additionally, these funds are invested in United States and international securities of approximately 42% and 58%, respectively, for 2019 and 41% and 59%, respectively, for 2018.

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.

Defined Contribution Plan

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 $23 million, $22 million, and $20 million for the years ended December 31, 2019, 2018 and 2017, respectively.

(11) Asset Retirement Obligations

MidAmerican Energy estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

MidAmerican Energy does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $572 million and $708 million as of December 31, 2019 and 2018, respectively.

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

	2019	2018
Quad Cities Station	$ 358	$ 345
Fossil-fueled generating facilities	325	93
Wind-powered generating facilities	154	123
Other	2	1
Total asset retirement obligations	$ 839	$ 562
Quad Cities Station nuclear decommissioning trust funds(1)	$ 599	$ 504

(1) Refer to Note 6 for a discussion of the Quad Cities Station nuclear decommissioning trust funds.

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

	2019	2018
Beginning balance	$ 562	$ 559
Change in estimated costs	234	(10)
Additions	27	17
Retirements	(14)	(28)
Accretion	30	24
Ending balance	$ 839	$ 562
Reflected as:		
Other current liabilities	$ 135	$ 10
Asset retirement obligations	704	552
	$ 839	$ 562

In January 2018, MidAmerican Energy completed groundwater testing at its coal combustion residuals ("CCR") surface impoundments. Based on this information, MidAmerican Energy discontinued sending CCR to surface impoundments effective April 2018 and initiated analysis of additional actions to be taken. As a result of that analysis, MidAmerican Energy will remove all CCR material located below the water table and cap the material in such facilities, which is a more extensive closure activity than previously assumed. In the first quarter of 2019, MidAmerican Energy increased the asset retirement obligations for its fossil-fueled generating facilities by $237 million related to the cost of this closure activity. Closure activity on the six existing surface impoundments is estimated to extend through 2023.

(12) 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, 2019:					
Assets:					
Commodity derivatives	$ —	$ 2	$ 1	$ (1)	$ 2
Money market mutual funds[(2)]	274	—	—	—	274
Debt securities:					
United States government obligations	189	—	—	—	189
International government obligations	—	4	—	—	4
Corporate obligations	—	58	—	—	58
Municipal obligations	—	1	—	—	1
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
United States companies	336	—	—	—	336
International companies	9	—	—	—	9
Investment funds	15	—	—	—	15
	$ 823	$ 66	$ 1	$ (1)	$ 889
Liabilities - commodity derivatives	$ —	$ (9)	$ —	$ 2	$ (7)
As of December 31, 2018					
Assets:					
Commodity derivatives	$ —	$ 4	$ 2	$ (3)	$ 3
Money market mutual funds[(2)]	2	—	—	—	2
Debt securities:					
United States government obligations	187	—	—	—	187
International government obligations	—	4	—	—	4
Corporate obligations	—	46	—	—	46
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
United States companies	256	—	—	—	256
International companies	6	—	—	—	6
Investment funds	10	—	—	—	10
	$ 461	$ 57	$ 2	$ (3)	$ 517
Liabilities:					
Commodity derivatives	$ —	$ (4)	$ (2)	$ 3	$ (3)
Interest rate derivatives[(3)]	$ —	$ (19)	$ —	$ —	$ (19)
	$ —	$ (23)	$ (2)	$ 3	$ (22)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $1 million and $- million as of December 31, 2019 and 2018, respectively.

(2) Amounts are included in cash and cash equivalents and investments and restricted investments on the Balance Sheets. The fair value of these money market mutual funds approximates cost.

(3) The interest rate derivatives were interest rate locks related to MidAmerican Energy's January 2019 issuance of first mortgage bonds.

MidAmerican Energy's investments in money market mutual funds and debt and equity securities are stated at fair value, with debt securities 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.

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):

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,208	$ 8,283	$ 5,379	$ 5,644

(13) 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, 2019, are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 114	$ 52	$ 48	$ 39	$ —	$ —	$ 253
Electric capacity and transmission	28	24	14	8	7	29	110
Natural gas contracts for gas operations	102	61	47	24	8	23	265
Construction commitments	670	515	27	2	4	—	1,218
Easements	32	36	37	38	39	1,492	1,674
Maintenance, services and other	198	156	154	155	120	432	1,215
	$ 1,144	$ 844	$ 327	$ 266	$ 178	$ 1,976	$ 4,735

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 2023.

MidAmerican Energy has various natural gas supply and transportation contracts for its regulated natural 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 2020 and 2021 firm construction commitments reflected in the table above consist primarily of contracts for the construction and repowering of wind-powered generating facilities and the settlement of asset retirement obligations.

Easements

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.

Maintenance, Services and Other Contracts

MidAmerican Energy has other non-cancelable contracts primarily related to maintenance and services for various generating facilities with minimum payment commitments ranging through 2029.

Environmental Laws and Regulations

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

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. MidAmerican Energy is authorized by the FERC to include a 0.50% adder beyond the base ROE effective January 2015. 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. In September 2016, the FERC issued an order for the first complaint, which reduced the base ROE to 10.32% and required refunds, plus interest, for the period from November 2013 through February 2015. Customer refunds relative to the first complaint occurred in February 2017. In November 2019, the FERC issued an order addressing the second complaint and issues on appeal in the first complaint. The order established an ROE of 9.88% (10.38% including the 0.50% adder) for the 15-month refund period of the first complaint and prospectively from September 2016 forward. The order indicated no refunds were necessary for the period February 2015 through September 2016. The order has been appealed, and MidAmerican Energy has accrued a $16 million liability for refunds of amounts collected under the higher ROE during the periods covered by both complaints.

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.

(14) Revenue from Contracts with Customers

MidAmerican Energy uses a single five-step model to identify and recognizes revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. The following table summarizes MidAmerican Energy's revenue by line of business and customer class, including a reconciliation to MidAmerican Energy's reportable segment information included in Note 18, (in millions):

	For the Year Ended December 31,							
	2019				2018			
	Electric	Natural Gas	Other	Total	Electric	Natural Gas	Other	Total
Customer Revenue:								
Retail:								
Residential	$ 672	$ 383	$ —	$ 1,055	$ 696	$ 421	$ —	$ 1,117
Commercial	322	132	—	454	314	153	—	467
Industrial	799	17	—	816	758	22	—	780
Natural gas transportation services	—	38	—	38	—	39	—	39
Other retail	145	—	—	145	147	1	—	148
Total retail	1,938	570	—	2,508	1,915	636	—	2,551
Wholesale	221	88	—	309	295	116	—	411
Multi-value transmission projects	57	—	—	57	55	—	—	55
Other Customer Revenue	—	—	28	28	—	—	11	11
Total Customer Revenue	2,216	658	28	2,902	2,265	752	11	3,028
Other revenue	21	2	—	23	18	2	1	21
Total operating revenue	$ 2,237	$ 660	$ 28	$ 2,925	$ 2,283	$ 754	$ 12	$ 3,049

(15) Other Income (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):

	2019	2018	2017
Non-service cost components of postretirement employee benefit plans	$ 17	$ 21	$ 18
Corporate-owned life insurance income	24	6	13
Interest income and other, net	9	3	6
Total	$ 50	$ 30	$ 37

(16) Supplemental Cash Flow Disclosures

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 cash and cash equivalents as of December 31, 2019 and 2018, consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and 2018 as presented in the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Balance Sheets (in millions):

	As of December 31,	
	2019	2018
Cash and cash equivalents	$ 287	$ —
Restricted cash and cash equivalents in other current assets	43	56
Total cash and cash equivalents and restricted cash and cash equivalents	$ 330	$ 56

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

	2019	2018	2017
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 224	$ 198	$ 193
Income taxes received, net	$ 450	$ 494	$ 465
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 337	$ 371	$ 224

(17) 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 $43 million, $51 million and $53 million for 2019, 2018 and 2017, respectively. Additionally, in 2018, MidAmerican Energy received $15 million from BHE for the transfer of a corporate aircraft.

MidAmerican Energy reimbursed BHE in the amount of $14 million, $11 million and $9 million in 2019, 2018 and 2017, 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, an indirect wholly owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $139 million, $127 million and $122 million in 2019, 2018 and 2017, respectively.

MidAmerican Energy had accounts receivable from affiliates of $6 million and $8 million as of December 31, 2019 and 2018, respectively, that are included in receivables on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $11 million and $12 million as of December 31, 2019 and 2018, 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 payable to BHE of $82 million and $156 million as of December 31, 2019 and 2018, respectively. MidAmerican Energy received net cash receipts for federal and state income taxes from BHE totaling $450 million, $494 million and $465 million for the years ended December 31, 2019, 2018 and 2017, 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 $23 million and $20 million as of December 31, 2019 and 2018, respectively, and similar amounts payable to affiliates totaled $47 million and $36 million as of December 31, 2019 and 2018, respectively. See Note 10 for further information pertaining to pension and postretirement accounting.

(18) Segment Information

MidAmerican Energy 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 gas owned by others through its distribution system. Pricing for regulated electric and regulated natural 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 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2019	2018	2017
Operating revenue:			
Regulated electric	$ 2,237	$ 2,283	$ 2,108
Regulated natural gas	660	754	719
Other	28	12	10
Total operating revenue	$ 2,925	$ 3,049	$ 2,837
Depreciation and amortization:			
Regulated electric	$ 593	$ 565	$ 458
Regulated natural gas	46	44	42
Total depreciation and amortization	$ 639	$ 609	$ 500
Operating income:			
Regulated electric	$ 473	$ 469	$ 472
Regulated natural gas	71	81	72
Other	4	1	(1)
Total operating income	$ 548	$ 551	$ 543
Interest expense:			
Regulated electric	$ 259	$ 208	$ 196
Regulated natural gas	22	19	18
Total interest expense	$ 281	$ 227	$ 214

	Years Ended December 31,		
	2019	2018	2017
Income tax (benefit) expense:			
Regulated electric	$ (384)	$ (273)	$ (212)
Regulated natural gas	12	16	29
Other	1	2	—
Total income tax (benefit) expense	$ (371)	$ (255)	$ (183)
Net income:			
Regulated electric	$ 739	$ 628	$ 570
Regulated natural gas	52	54	35
Other	2	—	—
Net income	$ 793	$ 682	$ 605
Capital expenditures:			
Regulated electric	$ 2,684	$ 2,223	$ 1,686
Regulated natural gas	126	109	87
Total capital expenditures	$ 2,810	$ 2,332	$ 1,773

	As of December 31,		
	2019	2018	2017
Total assets:			
Regulated electric	$ 19,093	$ 16,511	$ 14,914
Regulated natural gas	1,468	1,406	1,403
Other	3	3	1
Total assets	$ 20,564	$ 17,920	$ 16,318

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, 2019 and 2018, the related consolidated statements of operations, changes in member's equity, and cash flows, for each of the three years in the period ended December 31, 2019, and the related notes and the schedules listed in the Index at Item 15(a)(2) (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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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 21, 2020

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,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 288	$ 1
Trade receivables, net	291	365
Inventories	226	204
Other current assets	91	89
Total current assets	896	659
Property, plant and equipment, net	18,377	16,169
Goodwill	1,270	1,270
Regulatory assets	289	273
Investments and restricted investments	820	710
Other assets	188	121
Total assets	$ 21,840	$ 19,202

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,	
	2019	**2018**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 520	$ 575
Accrued interest	84	58
Accrued property, income and other taxes	226	300
Note payable to affiliate	171	156
Short-term debt	—	240
Current portion of long-term debt	—	500
Other current liabilities	219	122
Total current liabilities	1,220	1,951
Long-term debt	7,448	5,119
Regulatory liabilities	1,406	1,620
Deferred income taxes	2,621	2,319
Asset retirement obligations	704	552
Other long-term liabilities	340	312
Total liabilities	13,739	11,873
Commitments and contingencies (Note 13)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	6,422	5,650
Total member's equity	8,101	7,329
Total liabilities and member's equity	$ 21,840	$ 19,202

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,		
	2019	**2018**	**2017**
Operating revenue:			
Regulated electric	$ 2,237	$ 2,283	$ 2,108
Regulated natural gas and other	690	770	738
Total operating revenue	2,927	3,053	2,846
Operating expenses:			
Cost of fuel and energy	399	487	434
Cost of natural gas purchased for resale and other	412	469	447
Operations and maintenance	801	813	802
Depreciation and amortization	639	609	500
Property and other taxes	127	125	119
Total operating expenses	2,378	2,503	2,302
Operating income	549	550	544
Other income (expense):			
Interest expense	(302)	(247)	(237)
Allowance for borrowed funds	27	20	15
Allowance for equity funds	78	53	41
Other, net	52	31	9
Total other income (expense)	(145)	(143)	(172)
Income before income tax benefit	404	407	372
Income tax benefit	(377)	(262)	(202)
Net income	$ 781	$ 669	$ 574

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
(Amounts in millions)

	Paid-in Capital	Retained Earnings	Total Member's Equity
Balance, December 31, 2016	$ 1,679	$ 4,407	$ 6,086
Net income	—	574	574
Balance, December 31, 2017	1,679	4,981	6,660
Net income	—	669	669
Balance, December 31, 2018	1,679	5,650	7,329
Net income	—	781	781
Distribution to member	—	(8)	(8)
Other equity transactions	—	(1)	(1)
Balance, December 31, 2019	$ 1,679	$ 6,422	$ 8,101

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,		
	2019	**2018**	**2017**
Cash flows from operating activities:			
Net income	$ 781	$ 669	$ 574
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss on other items	—	—	29
Depreciation and amortization	639	609	500
Amortization of utility plant to other operating expenses	33	34	34
Allowance for equity funds	(78)	(53)	(41)
Deferred income taxes and amortization of investment tax credits	152	32	334
Other, net	(8)	16	(14)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	56	(19)	(62)
Inventories	(22)	41	19
Derivative collateral, net	(1)	(1)	2
Contributions to pension and other postretirement benefit plans, net	(10)	(13)	(11)
Accrued property, income and other taxes, net	(74)	230	(54)
Accounts payable and other liabilities	7	(29)	70
Net cash flows from operating activities	1,475	1,516	1,380
Cash flows from investing activities:			
Capital expenditures	(2,810)	(2,332)	(1,773)
Purchases of marketable securities	(156)	(263)	(143)
Proceeds from sales of marketable securities	138	223	137
Proceeds from sales of other investments	1	17	2
Other investment proceeds	13	15	1
Other, net	13	30	(3)
Net cash flows from investing activities	(2,801)	(2,310)	(1,779)
Cash flows from financing activities:			
Proceeds from long-term debt	2,326	687	990
Repayments of long-term debt	(500)	(350)	(341)
Net change in note payable to affiliate	15	(8)	133
Net (repayments of) proceeds from short-term debt	(240)	240	(99)
Tender offer premium paid	—	—	(29)
Other, net	(1)	—	—
Net cash flows from financing activities	1,600	569	654
Net change in cash and cash equivalents and restricted cash and cash equivalents	274	(225)	255
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	57	282	27
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 331	$ 57	$ 282

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Funding, LLC ("MidAmerican Funding") is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. 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"). 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, and its direct, wholly owned nonregulated subsidiary is Midwest Capital Group, Inc. ("Midwest Capital Group").

(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. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2019, 2018 and 2017.

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 2019, 2018 and 2017, MidAmerican Funding did not record any goodwill impairments.

(3) Property, Plant and Equipment, Net

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MidAmerican Funding had nonregulated property gross of $3 million and $24 million as of December 31, 2019 and 2018, respectively, and related accumulated depreciation and amortization of $1 million and $12 million as of December 31, 2019 and 2018, respectively, which, as of December 31, 2018, consisted primarily of a corporate aircraft owned by MHC. In 2019, MHC transferred the aircraft by dividend to MidAmerican Funding, which transferred it to BHE.

(4) Jointly Owned Utility Facilities

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements.

(5) Regulatory Matters

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements.

(6) Investments and Restricted Investments

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted 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, 2019 and 2018.

(7) Short-Term Debt and Credit Facilities

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2020 and has a variable interest rate based on the Eurodollar rate plus a spread. As of December 31, 2019 and 2018, there were no borrowings outstanding under this credit facility. As of December 31, 2019, MHC was in compliance with the covenants of its credit facility.

(8) Long-Term Debt

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for detail and a discussion of its long-term debt. In addition to MidAmerican Energy's annual repayments of long-term debt, MidAmerican Funding has $239 million of 6.927% Senior Bonds due in 2029, with a carrying value of $240 million as of December 31, 2019 and 2018. 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 (expense) 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 8 of MidAmerican Energy's Notes to Financial Statements for a discussion of utility regulatory restrictions affecting distributions from MidAmerican Energy. As a result of the utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, MidAmerican Funding had restricted net assets of $5.2 billion as of December 31, 2019.

As of December 31, 2019, MidAmerican Funding was in compliance with all of its applicable long-term debt covenants.

Each of MidAmerican Funding's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Funding and its other subsidiaries. It should not be assumed that any asset of any subsidiary of MidAmerican Funding will be available to satisfy the obligations of MidAmerican Funding or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MidAmerican Funding, one of its subsidiaries or affiliates thereof.

(9) Income Taxes

MidAmerican Funding's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2019	2018	2017
Current:			
Federal	$ (480)	$ (280)	$ (505)
State	(49)	(14)	(31)
	(529)	(294)	(536)
Deferred:			
Federal	164	42	338
State	(11)	(9)	(3)
	153	33	335
Investment tax credits	(1)	(1)	(1)
Total	$ (377)	$ (262)	$ (202)

A reconciliation of the federal statutory income tax rate to MidAmerican Funding's effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2019	2018	2017
Federal statutory income tax rate	21 %	21 %	35 %
Income tax credits	(94)	(76)	(77)
State income tax, net of federal income tax benefit	(12)	(4)	(6)
Effects of ratemaking	(8)	(6)	(8)
Other, net	—	1	2
Effective income tax rate	(93)%	(64)%	(54)%

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

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 368	$ 405
Asset retirement obligations	234	164
Employee benefits	26	47
Other	76	85
Total deferred income tax assets	704	701
Deferred income tax liabilities:		
Depreciable property	(3,253)	(2,947)
Regulatory assets	(68)	(62)
Other	(4)	(11)
Total deferred income tax liabilities	(3,325)	(3,020)
Net deferred income tax liability	$ (2,621)	$ (2,319)

As of December 31, 2019, MidAmerican Funding has available $51 million of state tax carryforwards, principally related to $745 million of net operating losses, that expire at various intervals between 2020 and 2038.

The United States Internal Revenue Service has closed its examination MidAmerican Funding's income tax returns through December 31, 2011. The statute of limitations for MidAmerican Funding's state income tax returns have expired through December 31, 2009, with the exception of Iowa and Illinois, for which the statute of limitations have expired through December 31, 2015, except for the impact of any federal audit adjustments. 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 statute of limitations is not closed.

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):

	2019	2018
Beginning balance	$ 10	$ 12
Additions based on tax positions related to the current year	5	4
Additions for tax positions of prior years	10	47
Reductions based on tax positions related to the current year	(5)	(4)
Reductions for tax positions of prior years	(12)	(48)
Interest and penalties	—	(1)
Ending balance	$ 8	$ 10

As of December 31, 2019, MidAmerican Funding had unrecognized tax benefits totaling $27 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Funding's effective income tax rate.

(10) Employee Benefit Plans

Refer to Note 10 of MidAmerican Energy's Notes to Financial Statements for additional information regarding MidAmerican Funding's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MidAmerican Funding to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2019	2018	2017
Pension costs	$ 4	$ 3	$ 4
Other postretirement costs	(2)	(2)	(3)

(11) Asset Retirement Obligations

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements.

(12) Fair Value Measurements

Refer to Note 12 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):

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,448	$ 8,599	$ 5,619	$ 5,941

(13) Commitments and Contingencies

Refer to Note 13 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.

(14) Revenue from Contracts with Customers

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements. Additionally, MidAmerican Funding had $2 million and $4 million of other revenue from contracts with customers for the year ended December 31, 2019 and 2018, respectively.

(15) Other Income (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):

	2019	2018	2017
Non-service cost components of postretirement employee benefit plans	$ 17	$ 21	$ 18
Corporate-owned life insurance income	24	6	13
Loss on debt tender offer	—	—	(29)
Interest income and other, net	11	4	7
Total	$ 52	$ 31	$ 9

Refer to Note 8 for information regarding the debt tender offer.

(16) Supplemental Cash Flow Information

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 cash and cash equivalents as of December 31, 2019 and 2018, consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and 2018 as presented in the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2019	2018
Cash and cash equivalents	$ 288	$ 1
Restricted cash and cash equivalents in other current assets	43	56
Total cash and cash equivalents and restricted cash and cash equivalents	$ 331	$ 57

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

	2019	2018	2017
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 245	$ 218	$ 218
Income taxes received, net	$ 456	$ 511	$ 472
Supplemental disclosure of non-cash investing and financing transactions:			
Accounts payable related to utility plant additions	$ 337	$ 371	$ 224
Distribution of corporate aircraft to parent	$ 8	$ —	$ —

(17) 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 $41 million, $44 million and $46 million for 2019, 2018 and 2017, respectively. Additionally, in 2018, MidAmerican Funding received $15 million from BHE for the transfer of corporate aircraft owned by MidAmerican Energy and, in 2019, recorded a noncash dividend of $8 million for the transfer to BHE of corporate aircraft owned by MHC.

MidAmerican Funding reimbursed BHE in the amount of $14 million, $11 million and $9 million in 2019, 2018 and 2017, 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 $139 million, $127 million and $122 million in 2019, 2018 and 2017, 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 $171 million at an interest rate of 1.944% as of December 31, 2019, and $156 million at an interest rate of 2.629% as of December 31, 2018, 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 2019 and 2018.

MidAmerican Funding had accounts receivable from affiliates of $7 million and $5 million as of December 31, 2019 and 2018, respectively, that are included in receivables, net on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $11 million and $12 million as of December 31, 2019 and 2018, 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 payable to BHE of $83 million and $156 million as of December 31, 2019 and 2018, respectively. MidAmerican Funding received net cash receipts for federal and state income taxes from BHE totaling $456 million, $511 million and $472 million for the years ended December 31, 2019, 2018 and 2017, 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 $23 million and $20 million as of December 31, 2019 and 2018, respectively, and similar amounts payable to affiliates totaled $47 million and $36 million as of December 31, 2019 and 2018, respectively. See Note 10 for further information pertaining to pension and postretirement accounting.

The indenture pertaining to MidAmerican Funding's long-term debt restricts MidAmerican Funding from paying a distribution on its equity securities, unless after making such distribution either its debt to total capital ratio does not exceed 0.67:1 and its interest coverage ratio is not less than 2.2:1 or its senior secured long-term debt rating is at least BBB or its equivalent. MidAmerican Funding may seek a release from this restriction upon delivery to the indenture trustee of written confirmation from the ratings agencies that without this restriction MidAmerican Funding's senior secured long-term debt would be rated at least BBB+.

(18) Segment Information

MidAmerican Funding 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 gas owned by others through its distribution system. Pricing for regulated electric and regulated natural 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 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2019	2018	2017
Operating revenue:			
Regulated electric	$ 2,237	$ 2,283	$ 2,108
Regulated natural gas	660	754	719
Other	30	16	19
Total operating revenue	$ 2,927	$ 3,053	$ 2,846
Depreciation and amortization:			
Regulated electric	$ 593	$ 565	$ 458
Regulated natural gas	46	44	42
Total depreciation and amortization	$ 639	$ 609	$ 500
Operating income:			
Regulated electric	$ 473	$ 469	$ 472
Regulated natural gas	71	81	72
Other	5	—	—
Total operating income	$ 549	$ 550	$ 544
Interest expense:			
Regulated electric	$ 259	$ 208	$ 196
Regulated natural gas	22	19	18
Other	21	20	23
Total interest expense	$ 302	$ 247	$ 237
Income tax (benefit) expense:			
Regulated electric	$ (384)	$ (273)	$ (212)
Regulated natural gas	12	16	29
Other	(5)	(5)	(19)
Total income tax (benefit) expense	$ (377)	$ (262)	$ (202)
Net income:			
Regulated electric	$ 739	$ 628	$ 570
Regulated natural gas	52	54	35
Other	(10)	(13)	(31)
Net income	$ 781	$ 669	$ 574

	Years Ended December 31,		
	2019	2018	2017
Capital expenditures:			
Regulated electric	$ 2,684	$ 2,223	$ 1,686
Regulated natural gas	126	109	87
Total capital expenditures	$ 2,810	$ 2,332	$ 1,773

	As of December 31,		
	2019	2018	2017
Total assets:			
Regulated electric	$ 20,284	$ 17,702	$ 16,105
Regulated natural gas	1,547	1,485	1,482
Other	9	15	34
Total assets	$ 21,840	$ 19,202	$ 17,621

Goodwill by reportable segment as of December 31, 2019 and 2018, was as follows (in millions):

Regulated electric	$ 1,191
Regulated natural gas	79
Total	$ 1,270

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

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, usage trends 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

Overview

Net income for the year ended December 31, 2019 was $264 million, an increase of $38 million, or 17%, compared to 2018, primarily due to $119 million of lower operations and maintenance, mainly due to lower political activity expenses, a lower accrual for earnings sharing and lower settlement costs associated with a personal injury claim in 2018. The increase is partially offset by $62 million of lower utility margin, mainly due to lower customer volumes from the unfavorable impacts of weather and lower average retail rates related to the tax rate reduction rider effective April 2018, and $20 million of higher depreciation and amortization expense, primarily due to higher plant placed in service.

Net income for the year ended December 31, 2018 was $226 million, a decrease of $29 million, or 11%, compared to 2017, primarily due to $52 million of higher operations and maintenance expense, mainly due to an accrual for earnings sharing established in 2018 as part of the Nevada Power 2017 regulatory rate review and increased political activity expenses, $37 million of lower utility margin and higher depreciation and amortization, primarily due to various regulatory-directed amortizations established in the Nevada Power 2017 regulatory rate review. These decreases were partially offset by lower income tax expense of $84 million, primarily from a lower federal tax rate due to the impact of the Tax Cuts and Jobs Act (the "2017 Tax Reform") and $9 million of lower interest expense on long-term debt. Utility margins decreased due to lower average retail rates including rate impacts related to the tax rate reduction rider as a result of 2017 Tax Reform and lower margins from customers purchasing energy from alternative providers and becoming distribution only service customers, partially offset by higher residential, commercial and industrial volumes.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as, utility margin, to help evaluate results of operations. Utility margin is calculated as operating revenue less cost of fuel and energy, which are captions presented on the Consolidated Statements of Operations.

Nevada Power's cost of fuel and energy is generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in Nevada Power's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes utility margin more appropriately and concisely explains profitability rather than a discussion of revenue and cost of fuel and energy separately. Management believes the presentation of utility margin provides meaningful and valuable insight into the information management considers important to running the business and a measure of comparability to others in the industry.

Utility margin is not a measure calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2019	2018	Change		2018	2017	Change	
Utility margin:								
Operating revenue	$ 2,148	$ 2,184	$ (36)	(2)%	$ 2,184	$ 2,206	$ (22)	(1)%
Cost of fuel and energy	943	917	26	3	917	902	15	2
Utility margin	1,205	1,267	(62)	(5)	1,267	1,304	(37)	(3)
Operations and maintenance	324	443	(119)	(27)	443	391	52	13
Depreciation and amortization	357	337	20	6	337	308	29	9
Property and other taxes	45	41	4	10	41	40	1	3
Operating income	$ 479	$ 446	$ 33	7 %	$ 446	$ 565	$ (119)	(21)%

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2019	2018	Change		2018	2017	Change	
Utility margin (in millions):								
Operating revenue	$ 2,148	$ 2,184	$ (36)	(2)%	$ 2,184	$ 2,206	$ (22)	(1)%
Cost of fuel and energy	943	917	26	3	917	902	15	2
Utility margin	$ 1,205	$ 1,267	$ (62)	(5)%	$ 1,267	$ 1,304	$ (37)	(3)%
GWhs sold:								
Residential	9,311	9,970	(659)	(7)%	9,970	9,501	469	5 %
Commercial	4,657	4,778	(121)	(3)	4,778	4,656	122	3
Industrial	5,344	5,534	(190)	(3)	5,534	6,201	(667)	(11)
Other	193	214	(21)	(10)	214	212	2	1
Total fully bundled[1]	19,505	20,496	(991)	(5)	20,496	20,570	(74)	—
Distribution only service	2,613	2,521	92	4	2,521	1,830	691	38
Total retail	22,118	23,017	(899)	(4)	23,017	22,400	617	3
Wholesale	527	274	253	92	274	314	(40)	(13)
Total GWhs sold	22,645	23,291	(646)	(3)%	23,291	22,714	577	3 %
Average number of retail customers (in thousands):								
Residential	840	825	15	2 %	825	810	15	2 %
Commercial	109	108	1	1	108	106	2	2
Industrial	2	2	—	—	2	2	—	—
Total	951	935	16	2 %	935	918	17	2 %
Average per MWh:								
Revenue - fully bundled[1]	$ 105.88	$ 102.82	$ 3.06	3 %	$ 102.82	$ 104.57	$ (1.75)	(2)%
Revenue - wholesale	$ 35.87	$ 40.31	$ (4.44)	(11)%	$ 40.31	$ 37.26	$ 3.05	8 %
Cost of energy[2][3]	$ 46.06	$ 42.17	$ 3.89	9 %	$ 42.17	$ 41.84	$ 0.33	1 %
Heating degree days	1,875	1,527	348	23 %	1,527	1,265	262	21 %
Cooling degree days	3,648	4,255	(607)	(14)%	4,255	4,044	211	5 %
Sources of energy (GWhs)[3][4]:								
Natural gas	13,161	13,848	(687)	(5)%	13,848	13,172	676	5 %
Coal	1,059	1,231	(172)	(14)	1,231	1,449	(218)	(15)
Renewables	61	69	(8)	(12)	69	73	(4)	(5)
Total energy generated	14,281	15,148	(867)	(6)	15,148	14,694	454	3
Energy purchased	6,167	6,587	(420)	(6)	6,587	6,858	(271)	(4)
Total	20,448	21,735	(1,287)	(6)%	21,735	21,552	183	1 %

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost per MWh of energy includes only the cost of fuel associated with the generating facilities, purchased power and deferrals.

(3) The average cost per MWh of energy and sources of energy excludes 153, 153 and 296 GWhs of coal and 1,756, 1,483 and 2,373 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2019, 2018 and 2017, respectively.

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

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Utility margin decreased $62 million for 2019 compared to 2018 primarily due to:

- $51 million in lower customer volumes primarily from the unfavorable impacts of weather;
- $11 million in lower retail rates due to the tax rate reduction rider effective April 2018;
- $4 million from lower transmission revenue; and
- $3 million due to lower retail rates as a result of the 2017 regulatory rate review with rates effective February 2018.

The decrease in utility margin was offset by:

- $7 million due to residential and commercial customer growth.

Operations and maintenance decreased $119 million, or 27%, for 2019 compared to 2018 primarily due to the impacts of adopting ASC 842 of $50 million, lower political activity expenses, a lower accrual for earnings sharing of $19 million and settlement costs associated with a personal injury claim in 2018 of $8 million.

Depreciation and amortization increased $20 million, or 6%, for 2019 compared to 2018 primarily due to the impacts of adopting ASC 842 of $13 million and higher plant placed in service.

Property and other taxes increased $4 million, or 10%, for 2019 compared to 2018 primarily due to a decrease in available abatements.

Other income (expense) is favorable $6 million, or 4%, for 2019 compared to 2018 primarily due to lower interest expense on long-term debt and regulatory liabilities of $36 million, higher dividend and interest income of $7 million and higher other income due to a licensing agreement with a third party of $2 million, partially offset by the impacts of adopting ASC 842 of $37 million and higher non-service pension expense of $5 million.

Income tax expense increased $1 million, or 1%, for 2019 compared to 2018. The effective tax rate was 22% in 2019 and 24% in 2018 and decreased due to lower nondeductible expenses.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Utility margin decreased $37 million for 2018 compared to 2017 due to:

- $51 million in lower retail rates due to the tax rate reduction rider as a result of 2017 Tax Reform;
- $30 million due to lower retail rates as a result of the 2017 regulatory rate review with rates effective February 2018; and
- $20 million in lower commercial and industrial retail revenue from customers purchasing energy from alternative providers and becoming distribution-only service customers.

The decrease in utility margin was partially offset by:

- $20 million in higher residential volumes primarily from the impacts of weather;
- $20 million in higher commercial and industrial volumes;
- $11 million in higher other revenue primarily from impact fees and revenue relating to customers becoming distribution-only service customers;
- $9 million due to residential customer growth; and
- $4 million in higher energy efficiency program rate revenue, which is offset in operations and maintenance expense.

Operations and maintenance increased $52 million, or 13%, for 2018 compared to 2017 primarily due to an accrual for earnings sharing established in 2018 as part of the Nevada Power 2017 regulatory rate review and increased political activity expenses, partially offset by disallowances in 2017 resulting from regulatory rate reviews.

Depreciation and amortization increased $29 million, or 9%, for 2018 compared to 2017 primarily due to various regulatory-directed amortizations and increased depreciation expense as a result of the Nevada Power 2017 regulatory rate review.

Other income (expense) is favorable $6 million, or 4%, for 2018 compared to 2017 primarily due to lower interest expense on long-term debt, partially offset by an unfavorable clarification order from the 2017 regulatory rate review to record carrying charges on impact fees received from customers that elected to become distribution only service customers and losses on investments.

Income tax expense decreased $84 million, or 54%, for 2018 compared to 2017. The effective tax rate was 24% in 2018 and 38% in 2017. The decrease in the effective tax rate is primarily due to 2017 Tax Reform, which reduced the United States federal corporate income tax rate from 35% to 21%, effective January 1, 2018, partially offset by an increase in nondeductible expenses.

Liquidity and Capital Resources

As of December 31, 2019, Nevada Power's total net liquidity was $415 million as follows (in millions):

Cash and cash equivalents	$	15
Credit facilities[(1)]		400
Total net liquidity	$	415
Credit facilities:		
Maturity dates		2022

(1) Refer to Note 7 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, 2019 and 2018 were $701 million and $619 million, respectively. The change was primarily due to lower interest payments for long-term debt, lower payments for operating costs, mainly due to lower political activity expenses, a decrease in fuel costs, lower contributions to the pension plan and proceeds from a licensing agreement with a third party, partially offset by lower collections from customers due to the unfavorable impacts of weather and decreased collections of customer advances.

Net cash flows from operating activities for the years ended December 31, 2018 and 2017 were $619 million and $665 million, respectively. The change was due to impact fees received in 2017, higher contributions to the pension plan and higher payments for operating costs, partially offset by increased collections from customers due to higher deferred energy rates.

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, 2019 and 2018 were $(407) million and $(297) million, respectively. The change was primarily due to increased capital expenditures. Refer to “Future Uses of Cash” for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2018 and 2017 were $(297) million and $(343) million, respectively. The change was primarily due to the acquisition of the remaining 25% ownership in the Silverhawk generating station in 2017, partially offset by increased capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2019 and 2018 were $(390) million and $(267) million, respectively. The change was primarily due to lower proceeds from issuance of long-term debt and higher dividends paid to NV Energy, Inc. of $447 million in 2019, partially offset by lower repayments of long-term debt.

Net cash flows from financing activities for the years ended December 31, 2018 and 2017 were $(267) million and $(546) million, respectively. The change was due to greater proceeds from issuance of long-term debt and higher dividends paid to NV Energy, Inc. in 2017, partially offset by higher repayments of long-term debt.

Ability to Issue Debt

Nevada Power currently has an effective automatic registration statement with the SEC to issue an indeterminate amount of long-term debt securities through October 15, 2022. Additionally, Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2019, Nevada Power has financing authority from the PUCN consisting of the ability to issue long-term and short-term debt securities so long as the total amount of debt outstanding (excluding borrowings under Nevada Power's $400 million secured credit facility) does not exceed $3.2 billion as measured at the end of each calendar quarter. Nevada Power's revolving credit facility contains a financial maintenance covenant which Nevada Power was in compliance with as of December 31, 2019. 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, 2019, $8.7 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $3.3 billion of additional general and refunding mortgage securities as of December 31, 2019 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.

Long-Term Debt

In January 2019, Nevada Power issued $500 million of its 3.700% General and Refunding Mortgage Notes, Series CC, due May 2029. Nevada Power used the net proceeds to repay all of Nevada Power's $500 million 7.125% General and Refunding Mortgage Notes, Series V, maturing in March 2019.

In January 2020, Nevada Power issued $425 million of its 2.400% General and Refunding Mortgage Notes, Series DD, due May 2030 and issued $300 million of its 3.125% General and Refunding Mortgage Notes, Series EE, due August 2050. Nevada Power intends to use the net proceeds from the sale of the Notes to repay $575 million aggregate principal amount of its 2.750% General and Refunding Mortgage Notes, Series BB, maturing in April 2020 and for general corporate purposes.

In January 2020, Nevada Power issued a 30-day notice of early redemption to repay $575 million of its 2.750% General and Refunding Mortgage Notes, Series BB.

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		
	2017	2018	2019	2020	2021	2022
Generation development	$ —	$ —	$ —	$ 84	$ 47	$ 30
Distribution	110	137	209	242	88	142
Transmission system investment	9	9	10	21	6	23
Operating and other	151	150	185	149	140	78
Total	$ 270	$ 296	$ 404	$ 496	$ 281	$ 273

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.

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, 2019 (in millions):

	Payments Due by Periods				
	2020	2021 - 2022	2023 - 2024	2025 and Thereafter	Total
Long-term debt	$ 575	$ —	$ —	$ 1,809	$ 2,384
Interest payments on long-term debt(1)	103	190	190	1,126	1,609
ON Line finance lease liability	12	26	31	316	385
Interest payments on ON Line finance lease liability(1)	32	62	57	325	476
Operating and finance lease liabilities(2)	11	34	14	26	85
Interest payments on operating and finance lease liabilities(1)	7	10	5	4	26
Fuel and capacity contract commitments(1)(3)	539	709	645	3,432	5,325
Fuel and capacity contract commitments (not commercially operable)(1)(3)	1	47	249	4,677	4,974
Non-construction commitments(1)	23	—	—	—	23
Easements(1)	4	9	8	43	64
Asset retirement obligations	14	22	14	32	82
Maintenance, service and other contracts(1)	51	91	59	18	219
Total contractual cash obligations	$ 1,372	$ 1,200	$ 1,272	$ 11,808	$ 15,652

(1) Not reflected on the Consolidated Balance Sheets.

(2) Includes fuel and capacity contracts designated as a finance lease.

(3) Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated.

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 7) and asset retirement obligations (Note 11), 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 climate change, RPS, air and water quality, emissions performance standards, 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.

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, 2019, the applicable credit ratings obtained from 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, 2019, Nevada Power would have been required to post $22 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.

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 $0.8 billion and total regulatory liabilities were $1.3 billion as of December 31, 2019. Refer to Nevada Power's Note 6 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.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2019, 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 commissions. 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 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's income taxes.

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 $109 million as of December 31, 2019. 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 Note 2 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 all of 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.

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 7 and 8 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, 2019 and 2018, 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.

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, 2019, 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 Board of Directors and Shareholder of
Nevada Power Company

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, 2019 and 2018, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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 21, 2020
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, 2019		As of December 31, 2018	
ASSETS				
Current assets:				
Cash and cash equivalents	$	15	$	111
Trade receivables, net		215		233
Inventories		62		61
Regulatory assets		1		39
Prepayments		42		51
Other current assets		29		24
Total current assets		364		519
Property, plant and equipment, net		6,538		6,418
Finance lease right of use assets, net		441		450
Regulatory assets		800		878
Other assets		59		37
Total assets	$	8,202	$	8,302
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities:				
Accounts payable	$	194	$	187
Accrued interest		30		38
Accrued property, income and other taxes		25		30
Current portion of long-term debt		575		500
Current portion of finance lease obligations		24		20
Regulatory liabilities		93		49
Customer deposits		62		67
Other current liabilities		34		29
Total current liabilities		1,037		920
Long-term debt		1,776		1,853
Finance lease obligations		430		443
Regulatory liabilities		1,163		1,137
Deferred income taxes		714		749
Other long-term liabilities		285		296
Total liabilities		5,405		5,398
Commitments and contingencies (Note 13)				
Shareholder's equity:				
Common stock - $1.00 stated value, 1,000 shares authorized, issued and outstanding		—		—
Additional paid-in capital		2,308		2,308
Retained earnings		493		600
Accumulated other comprehensive loss, net		(4)		(4)
Total shareholder's equity		2,797		2,904
Total liabilities and shareholder's equity	$	8,202	$	8,302

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,		
	2019	**2018**	**2017**
Operating revenue	$ 2,148	$ 2,184	$ 2,206
Operating expenses:			
Cost of fuel and energy	943	917	902
Operations and maintenance	324	443	391
Depreciation and amortization	357	337	308
Property and other taxes	45	41	40
Total operating expenses	1,669	1,738	1,641
Operating income	479	446	565
Other income (expense):			
Interest expense	(171)	(170)	(179)
Allowance for borrowed funds	3	2	1
Allowance for equity funds	5	3	1
Other, net	21	17	23
Total other income (expense)	(142)	(148)	(154)
Income before income tax expense	337	298	411
Income tax expense	73	72	156
Net income	$ 264	$ 226	$ 255

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, 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
Net income	—	—	—	226	—	226
Balance, December 31, 2018	1,000	—	2,308	600	(4)	2,904
Net income	—	—	—	264	—	264
Dividends declared	—	—	—	(371)	—	(371)
Balance, December 31, 2019	1,000	$ —	$ 2,308	$ 493	$ (4)	$ 2,797

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,		
	2019	**2018**	**2017**
Cash flows from operating activities:			
Net income	$ 264	$ 226	$ 255
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss (gain) on nonrecurring items	1	—	(1)
Depreciation and amortization	357	337	308
Allowance for equity funds	(5)	(3)	(1)
Changes in regulatory assets and liabilities	27	83	50
Deferred income taxes and amortization of investment tax credits	(32)	(13)	94
Deferred energy	51	(11)	(16)
Amortization of deferred energy	43	16	16
Other, net	(6)	14	(3)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	19	5	6
Inventories	1	(1)	6
Accrued property, income and other taxes	(13)	(35)	(26)
Accounts payable and other liabilities	(6)	1	(23)
Net cash flows from operating activities	701	619	665
Cash flows from investing activities:			
Capital expenditures	(409)	(298)	(270)
Acquisitions	—	—	(77)
Proceeds from sale of assets	2	1	4
Net cash flows from investing activities	(407)	(297)	(343)
Cash flows from financing activities:			
Proceeds from long-term debt	495	573	91
Repayments of long-term debt	(500)	(824)	(75)
Dividends paid	(371)	—	(548)
Other, net	(14)	(16)	(14)
Net cash flows from financing activities	(390)	(267)	(546)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(96)	55	(224)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	121	66	290
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 25	$ 121	$ 66

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 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, 2019, 2018 and 2017.

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 current assets and other assets on the Consolidated Balance Sheets.

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on Nevada Power's assessment of the collectability 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. As of December 31, 2019 and 2018, the allowance for doubtful accounts totaled $15 million and $16 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets.

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 $62 million and $56 million as of December 31, 2019 and 2018, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $- million and $5 million as of December 31, 2019 and 2018, 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 2019 and 2018 was 7.83% and 7.95%, respectively.

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 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, 2019, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

Lessee

Nevada Power has non-cancelable operating leases primarily for land, generating facilities, vehicles and office equipment and finance leases consisting primarily of transmission assets, generating facilities, office space and vehicles. These leases generally require Nevada Power to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Nevada Power does not include options in its lease calculations unless there is a triggering event indicating Nevada Power is reasonably certain to exercise the option. Nevada Power's accounting policy is to not recognize lease obligations and corresponding right-of-use assets for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with ASC Topic 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

Nevada Power's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

Nevada Power's operating right-of-use assets are recorded in other assets and the operating lease liabilities are recorded in current and long-term other liabilities accordingly. The right-of-use assets and lease liabilities for finance leases as of December 31, 2018 have been reclassified from property, plant and equipment, net and current portion of long-term and long-term debt, respectively, to conform to the current period presentation.

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. Changes in deferred income tax assets and liabilities that are associated with 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 commissions. 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

Nevada Power uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Nevada Power expects to be entitled in exchange for those goods or services. 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.

Substantially all of Nevada Power's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of amounts not considered Customer Revenue within Accounting Standards Codification ("ASC") 606, "Revenue from Contracts with Customers" and revenue recognized in accordance with ASC 842, "Leases."

Revenue recognized is equal to what Nevada Power has the right to invoice as it corresponds directly with the value to the customer of Nevada Power's performance to date and includes billed and unbilled amounts. As of December 31, 2019 and 2018, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $109 million and $106 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. 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. In addition, Nevada Power has recognized contract assets of $9 million and $- million as of December 31, 2019 and 2018, respectively, due to Nevada Power's performance on certain contracts.

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 February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("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 on 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. Following the issuance of ASU No. 2016-02, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2016-02 but did not change the core principle of the guidance. Nevada Power has elected to utilize various practical expedients available to adopt ASU No. 2016-02, including (1) the package of three not requiring a reassessment of (i) whether any expired or existing contracts are or contain leases; (ii) the lease classification for any expired or existing leases; and (iii) initial direct costs for any existing leases; (2) using hindsight in determining the lease term; and (3) not requiring a reassessment of whether existing or expired land easements that were not previously accounted for as leases under ASC Topic 840 are or contain a lease under ASC Topic 842. Nevada Power adopted this guidance for all applicable contracts in-effect as of January 1, 2019 under a modified retrospective method and the adoption did not have a cumulative effect impact at the date of initial adoption.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2019	2018
Utility plant:			
Generation	30 - 55 years	$ 3,541	$ 3,720
Distribution	20 - 65 years	3,567	3,411
Transmission	45 - 70 years	1,444	1,439
General and intangible plant	5 - 65 years	741	716
Utility plant		9,293	9,286
Accumulated depreciation and amortization		(2,951)	(2,966)
Utility plant, net		6,342	6,320
Other non-regulated, net of accumulated depreciation and amortization	45 years	1	1
Plant, net		6,343	6,321
Construction work-in-progress		195	97
Property, plant and equipment, net		$ 6,538	$ 6,418

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, 2019, 2018 and 2017 was 3.3%, 3.2%, and 3.2%, respectively. Nevada Power is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate review filings.

Construction work-in-progress is related to the construction of regulated assets.

In January 2018, Nevada Power revised its electric depreciation rates based on the results of a new depreciation study performed in 2017, the most significant impact of which was 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 approximately increased depreciation and amortization expense by $7 million annually, based on depreciable plant balances at the time of the change.

(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, 2019 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Navajo Generating Station[(1)]	11%	$ 13	$ 2	$ —
ON Line Transmission Line	24	151	23	—
Other transmission facilities	Various	66	27	—
Total		$ 230	$ 52	$ —

(1) Represents Nevada Power's proportionate share of capitalized asset retirement costs to retire the Navajo Generating Station, which was shut down in November 2019.

(5) Leases

The following table summarizes Nevada Power's leases recorded on the Consolidated Balance Sheet (in millions):

	As of December 31, 2019
Right-of-use assets:	
Operating leases	$ 13
Finance leases	441
Total right-of-use assets	$ 454
Lease liabilities:	
Operating leases	$ 17
Finance leases	454
Total lease liabilities	$ 471

The following table summarizes Nevada Power's lease costs (in millions):

	Year Ended December 31, 2019
Variable	$ 434
Operating	3
Finance:	
Amortization	13
Interest	37
Total lease costs	$ 487
Weighted-average remaining lease term (years):	
Operating leases	7.5
Finance leases	30.6
Weighted-average discount rate:	
Operating leases	4.5%
Finance leases	8.7%

The following table summarizes Nevada Power's supplemental cash flow information relating to leases (in millions):

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ (3)
Operating cash flows from finance leases	(37)
Financing cash flows from finance leases	(14)
Right-of-use assets obtained in exchange for lease liabilities:	
Finance leases	$ 9

Nevada Power has the following remaining lease commitments as of (in millions):

	December 31, 2019		
	Operating	Finance	Total
2020	$ 3	$ 60	$ 63
2021	3	64	67
2022	3	62	65
2023	2	51	53
2024	2	52	54
Thereafter	7	664	671
Total undiscounted lease payments	20	953	973
Less - amounts representing interest	(3)	(499)	(502)
Lease liabilities	$ 17	$ 454	$ 471

	December 31, 2018[1]		
	Operating	Capital	Total
2019	$ 3	$ 59	$ 62
2020	3	59	62
2021	3	61	64
2022	3	60	63
2023	2	50	52
Thereafter	10	709	719
Total undiscounted lease payments	$ 24	$ 998	$ 1,022

(1) Amounts included for comparability and accounted for in accordance with ASC Topic 840, "Leases".

Operating and Finance Lease Obligations

Nevada Power's lease obligation primarily consists of a transmission line One Nevada Transmission Line ("ON Line"), which was placed in-service on December 31, 2013. Nevada Power and Sierra Pacific, collectively the ("Nevada Utilities"), entered into a long-term transmission use agreement, in which the Nevada Utilities have a 25% interest and Great Basin Transmission South, LLC has a 75% interest. 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. In December 2019, the PUCN ordered the Nevada Utilities to complete the procedures changing the ownership split to 75% for Nevada Power and 25% for Sierra Pacific, effective January 1, 2020. The term of the lease is 41 years with the agreement ending December 31, 2054. Total ON Line finance lease obligations of $385 million and $395 million were included on the Consolidated Balance Sheets as of December 31, 2019 and 2018, respectively. See Note 2 for further discussion of Nevada Power's other lease obligations.

(6) Regulatory Matters

Regulatory Assets

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	2019	2018
Decommissioning costs[(2)]	3 years	$ 241	$ 222
Deferred operating costs	9 years	136	152
Merger costs from 1999 merger	25 years	120	125
Employee benefit plans[(1)]	8 years	87	105
Asset retirement obligations	6 years	67	68
Legacy meters	13 years	49	53
ON Line deferrals	34 years	45	46
Abandoned projects	1 year	12	46
Deferred energy costs	1 year	—	47
Other	Various	44	53
Total regulatory assets		$ 801	$ 917
Reflected as:			
Current assets		$ 1	$ 39
Noncurrent assets		800	878
Total regulatory assets		$ 801	$ 917

(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) Amount includes regulatory assets with an indeterminate life of $104 million and $81 million as of December 31, 2019 and 2018, respectively.

Nevada Power had regulatory assets not earning a return on investment of $303 million and $334 million as of December 31, 2019 and 2018, 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 Liabilities

Regulatory liabilities represent amounts that are expected 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	2019	2018
Deferred income taxes[1]	Various	$ 681	$ 677
Cost of removal[2]	33 years	332	320
Impact fees[3]	2 years	72	86
Other	Various	171	103
Total regulatory liabilities		$ 1,256	$ 1,186
Reflected as:			
Current liabilities		$ 93	$ 49
Noncurrent liabilities		1,163	1,137
Total regulatory liabilities		$ 1,256	$ 1,186

(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.

(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.

(3) Amounts reduce 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.

2017 Tax Reform

In February 2018, Nevada Power made filings with the PUCN proposing a tax rate reduction rider for the lower annual income tax expense anticipated to result from 2017 Tax Reform for 2018 and beyond. In March 2018, the PUCN issued an order approving the rate reduction proposed by Nevada Power. The new rates were effective April 1, 2018. The order extended the procedural schedule to allow parties additional discovery relevant to 2017 Tax Reform and a hearing was held in July 2018. In September 2018, the PUCN issued an order directing Nevada Power to record the amortization of any excess protected accumulated deferred income tax arising from the 2017 Tax Reform as a regulatory liability effective January 1, 2018. Subsequently, Nevada Power filed a petition for reconsideration relating to the amortization of protected excess accumulated deferred income tax balances resulting from the 2017 Tax Reform. In November 2018, the PUCN issued an order granting reconsideration and reaffirming the September 2018 order. In December 2018, Nevada Power filed a petition for judicial review. In January 2019, intervening parties filed statements of intent to participate in the petition for judicial review. Nevada Power has filed opening briefs and the intervening parties have filed answering briefs. The hearing occurred in January 2020 and a ruling is expected in the first half of 2020.

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. When Nevada Power's regulatory earned rate of return for a calendar year exceeds the regulatory rate of return used to set base tariff general rates, it is obligated to refund energy efficiency implementation revenue previously collected for that year. In March 2019, Nevada Power filed an application to reset the EEIR and EEPR and to refund the EEIR revenue received in 2018, including carrying charges. In August 2019, the PUCN issued an order accepting a stipulation requiring Nevada Power to refund the 2018 revenue and reset the rates as filed effective October 1, 2019. The EEIR liability for Nevada Power is $8 million and $9 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2019 and 2018, respectively.

Emissions Reduction and Capacity Retirement Plan ("ERCR Plan")

In November 2019, the Navajo coal-fueled generating facility was retired. Nevada Power owned 11% of the facility and its net owned capacity was 255 MWs. The decommissioning was approved by the PUCN in May 2014 as a part of the filed ERCR Plan. The remaining net book value of $12 million was moved from property, plant and equipment, net to noncurrent regulatory assets on the Consolidated Balance Sheet in November 2019, in compliance with the ERCR Plan. Refer to Note 13 for additional information on the ERCR Plan.

(7) Credit Facility

Nevada Power has a $400 million secured credit facility expiring in June 2022. 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, 2019 and 2018, 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.

(8) Long-Term Debt

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	2019	2018
General and refunding mortgage securities:			
7.125% Series V, due 2019	$ —	$ —	$ 500
2.750%, Series BB, due 2020	575	575	574
3.700%, Series CC, due 2029	500	496	—
6.650% Series N, due 2036	367	358	358
6.750% Series R, due 2037	349	346	346
5.375% Series X, due 2040	250	248	247
5.450% Series Y, due 2041	250	237	236
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.800% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	40
1.600% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
1.600% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Total long-term debt	$ 2,384	$ 2,351	$ 2,353
Reflected as:			
Current portion of long-term debt		$ 575	$ 500
Long-term debt		1,776	1,853
Total long-term debt		$ 2,351	$ 2,353

(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

The annual repayments of long-term debt for the years beginning January 1, 2020 and thereafter, are as follows (in millions):

2020	$ 575
2025 and thereafter	1,809
Total	2,384
Unamortized premium, discount and debt issuance cost	(33)
Total	$ 2,351

In January 2020, Nevada Power issued $425 million of its 2.400% General and Refunding Mortgage Notes, Series DD, due May 2030 and issued $300 million of its 3.125% General and Refunding Mortgage Notes, Series EE, due August 2050. Nevada Power intends to use the net proceeds from the sale of the Notes to repay $575 million aggregate principal amount of its 2.750% General and Refunding Mortgage Notes, Series BB, maturing in April 2020 and for general corporate purposes.

In January 2020, Nevada Power issued a 30-day notice of early redemption to repay $575 million of its 2.750% General and Refunding Mortgage Notes, Series BB.

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, 2019, approximately $8.7 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

(9) Income Taxes

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

	2019	2018	2017
Current – Federal	$ 105	$ 84	$ 62
Deferred – Federal	(31)	(13)	95
Uncertain tax positions	—	2	—
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 73	$ 72	$ 156

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:

	2019	2018	2017
Federal statutory income tax rate	21%	21%	35%
Non-deductible expenses	—	3	—
Effect of ratemaking	—	—	1
Effect of tax rate change	—	—	1
Other	1	—	1
Effective income tax rate	22%	24%	38%

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

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 211	$ 209
Operating and finance leases	99	97
Employee benefits	14	15
Customer advances	19	18
Other	9	9
Total deferred income tax assets	352	348
Deferred income tax liabilities:		
Property related items	(797)	(799)
Regulatory assets	(166)	(196)
Operating and finance leases	(95)	(94)
Other	(8)	(8)
Total deferred income tax liabilities	(1,066)	(1,097)
Net deferred income tax liability	$ (714)	$ (749)

The United States Internal Revenue Service has closed its examination of NV Energy's consolidated income tax returns through December 31, 2008, and the statute of limitations has expired for NV Energy's consolidated income tax returns through the short year ended December 19, 2013. The statute of limitations expiring may not preclude the Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the examination is not closed.

(10) Employee Benefit Plans

Nevada Power is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Nevada Power. Nevada Power did not make any contributions to the Qualified Pension Plan for the year ended December 31, 2019 and contributed $19 million and $1 million to the Qualified Pension Plan for the years ended December 31, 2018 and 2017, respectively. Nevada Power contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2019, 2018 and 2017. Nevada Power did not make any contributions to the Other Postretirement Plans for the years ended December 31, 2019, 2018 and 2017. 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 payable to NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2019	2018
Qualified Pension Plan -		
Other long-term liabilities	$ 18	$ 26
Non-Qualified Pension Plans:		
Other current liabilities	1	1
Other long-term liabilities	9	9
Other Postretirement Plans -		
Other long-term liabilities	2	1

(11) 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 $332 million and $320 million as of December 31, 2019 and 2018, respectively.

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

	2019	2018
Waste water remediation	$ 37	$ 37
Evaporative ponds and dry ash landfills	12	12
Asbestos	—	5
Solar	2	2
Other	23	27
Total asset retirement obligations	$ 74	$ 83

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

	2019	2018
Beginning balance	$ 83	$ 80
Change in estimated costs	6	11
Retirements	(19)	(11)
Accretion	4	3
Ending balance	$ 74	$ 83
Reflected as:		
Other current liabilities	$ 14	$ 13
Other long-term liabilities	60	70
	$ 74	$ 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, retired in November 2019, 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.

(12) 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, 2019:				
Assets:				
Commodity derivatives	$ —	$ —	$ —	$ —
Money market mutual funds[1]	10	—	—	10
Investment funds	2	—	—	2
	$ 12	$ —	$ —	$ 12
Liabilities - commodity derivatives	$ —	$ —	$ (8)	$ (8)
As of December 31, 2018:				
Assets:				
Commodity derivatives	$ —	$ —	$ 7	$ 7
Money market mutual funds[1]	104	—	—	104
Investment funds	1	—	—	1
	$ 105	$ —	$ 7	$ 112
Liabilities - commodity derivatives	$ —	$ —	$ (4)	$ (4)

(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, 2019, 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.

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 net commodity derivative assets or liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2019	2018	2017
Beginning balance	$ 3	$ (3)	$ (14)
Changes in fair value recognized in regulatory assets or liabilities	(21)	4	(3)
Settlements	10	2	14
Ending balance	$ (8)	$ 3	$ (3)

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):

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 2,351	$ 2,848	$ 2,353	$ 2,651

(13) 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 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.

In compliance with Senate Bill No. 123, Nevada Power retired 255 MWs of coal-fueled generation in 2019 in addition to the 557 MWs of coal-fueled generation retired in 2017.Consistent with the Emissions Reduction and Capacity Replacement Plan ("ERCR Plan"), between 2014 and 2016, Nevada Power acquired 536 MWs of natural gas generating resources, executed long-term power purchase agreements for 200 MWs of nameplate renewable energy capacity and constructed a 15-MW solar photovoltaic facility. Nevada Power has the option to acquire 35 MWs of nameplate renewable energy capacity in the future under the ERCR Plan, subject to PUCN approval.

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.

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2019 are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 539	$ 390	$ 319	$ 321	$ 324	$ 3,432	$ 5,325
Fuel and capacity contract commitments (not commercially operable)	1	6	41	92	157	4,677	4,974
Construction commitments	23	—	—	—	—	—	23
Easements	4	4	5	5	3	43	64
Maintenance, service and other contracts	51	48	43	34	25	18	219
Total commitments	$ 618	$ 448	$ 408	$ 452	$ 509	$ 8,170	$ 10,605

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 2026 to 2067. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Nevada Power's lease commitments.

Natural Gas

Nevada Power's gas transportation contracts expire from 2022 to 2032 and the gas supply contracts expires from 2020 to 2021.

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.

Construction Commitments

Nevada Power's construction commitments included in the table above relate to firm commitments and include costs associated with certain generating plant projects.

Easements

Nevada Power has non-cancelable easements for land. Operations and maintenance expense on non-cancelable easements totaled $7 million, $4 million and $4 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Maintenance, Service and Other Contracts

Nevada Power has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2020 to 2027.

(14) Revenues from Contracts with Customers

The following table summarizes Nevada Power's revenue by customer class for the years ended December 31 (in millions):

	2019	2018
Customer Revenue:		
Retail:		
Residential	$ 1,141	$ 1,195
Commercial	441	433
Industrial	433	425
Other	20	24
Total fully bundled	2,035	2,077
Distribution only service	31	30
Total retail	2,066	2,107
Wholesale, transmission and other	57	53
Total Customer Revenue	2,123	2,160
Other revenue	25	24
Total revenue	$ 2,148	$ 2,184

(15) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

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 cash and cash equivalents as of December 31, 2019 and December 31, 2018, consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and December 31, 2018, as presented in the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of	
	December 31, 2019	December 31, 2018
Cash and cash equivalents	$ 15	$ 111
Restricted cash and cash equivalents included in other current assets	10	10
Total cash and cash equivalents and restricted cash and cash equivalents	$ 25	$ 121

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

	2019	2018	2017
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 126	$ 166	$ 167
Income taxes paid	$ 113	$ 117	$ 89
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 49	$ 34	$ 18

(16) 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 years ended December 31, 2019, 2018 and 2017.

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $52 million, $58 million and $66 million for the years ended December 31, 2019, 2018 and 2017. As of December 31, 2019 and 2018, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $4 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $2 million, $3 million and $3 million for the years ended December 31, 2019, 2018 and 2017, respectively. Receivables associated with these services were $- million as of December 31, 2019 and 2018. PacifiCorp provided electricity and the sale of renewable energy credits to Nevada Power of $- million for the years ended December 31, 2019, 2018 and 2017. Payables associated with these transactions were $- million as of December 31, 2019 and 2018.

Nevada Power provided electricity to Sierra Pacific of $84 million, $91 million and $104 million for the years ended December 31, 2019, 2018 and 2017, respectively. Receivables associated with these transactions were $5 million and $6 million as of December 31, 2019 and 2018, respectively. Nevada Power purchased electricity from Sierra Pacific of $25 million, $28 million and $21 million for the years ended December 31, 2019, 2018 and 2017, respectively. Payables associated with these transactions were $1 million as of December 31, 2019 and 2018.

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 and $- million for each of the years ending December 31, 2019, 2018 and 2017, respectively. NV Energy provided services to Nevada Power of $9 million, $7 million and $10 million for the years ending December 31, 2019, 2018 and 2017, respectively. Nevada Power provided services to Sierra Pacific of $26 million, $28 million and $27 million for the years ended December 31, 2019, 2018 and 2017, respectively. Sierra Pacific provided services to Nevada Power of $14 million, $15 million and $17 million for the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019 and 2018, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $26 million. There were no receivables due from NV Energy as of December 31, 2019 and 2018. As of December 31, 2019 and 2018, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $3 million and $5 million, respectively. There were no payables due to Sierra Pacific as of December 31, 2019 and 2018.

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 receivable from NV Energy were $7 million as of December 31, 2019 and federal income taxes payable to NV Energy were $4 million as of December 31, 2018. Nevada Power made cash payments of $113 million, $117 million and $89 million for federal income taxes for the years ended December 31, 2019, 2018 and 2017, 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.

(17) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019
Operating revenues	$ 395	$ 527	$ 806	$ 420
Operating income	45	123	244	67
Net income	6	69	165	24

	Three-Month Periods Ended			
	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
Operating revenues	$ 395	$ 562	$ 820	$ 407
Operating income	40	122	247	37
Net income	—	64	164	(2)

Sierra Pacific Power Company
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 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, usage trends and other factors. This discussion should be read in conjunction with Sierra Pacific's historical Financial Statements and Notes to 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

Overview

Net income for the year ended December 31, 2019 was $103 million, an increase of $11 million, or 12%, compared to 2018, primarily due to $18 million of lower operations and maintenance expense, mainly due to lower political activity expenses, $3 million of higher electric utility margin, mainly due to $6 million of higher transmission and wholesale revenues and $3 million of customer growth, partially offset by $6 million of lower average retail rates related to the tax rate reduction rider effective April 2018, and $3 million of higher natural gas utility margin, mainly due to higher customer volumes primarily from the impacts of weather. These increases are partially offset by $10 million of unfavorable other, net, mainly due to higher non-service pension expense, and $6 million of higher depreciation and amortization expense, primarily due to higher plant placed in service.

Net income for the year ended December 31, 2018 was $92 million, a decrease of $17 million, or 16%, compared to 2017, primarily due to $23 million of higher operations and maintenance expense, primarily due to increased political activity expenses and $15 million of lower electric utility margin, primarily due to lower average retail rates including rate impacts related to the tax rate reduction rider as a result of the Tax Cuts and Jobs Act (the "2017 Tax Reform"). These decreases were partially offset by lower income tax expense of $25 million, primarily from a lower federal tax rate due to the impact of the 2017 Tax Reform.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as, electric utility margin and natural gas utility margin, to help evaluate results of operations. Electric utility margin is calculated as electric operating revenue less cost of fuel and energy while natural gas utility margin is calculated as natural gas operating revenue less cost of natural gas purchased for resale, which are captions presented on the Statements of Operations.

Sierra Pacific's cost of fuel and energy and cost of natural gas purchased for resale are generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in Sierra Pacific's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes electric utility margin and natural gas utility margin more appropriately and concisely explains profitability rather than a discussion of revenue and cost of sales separately. Management believes the presentation of electric utility margin and natural gas utility margin provides meaningful and valuable insight into the information management considers important to running the business and a measure of comparability to others in the industry.

Electric utility margin and natural gas utility margin are not measures calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2019	2018	Change		2018	2017	Change	
Electric utility margin:								
Electric operating revenue	$ 770	$ 752	$ 18	2 %	$ 752	$ 713	$ 39	5 %
Cost of fuel and energy	337	322	15	5	322	268	54	20
Electric utility margin	433	430	3	1 %	430	445	(15)	(3)%
Natural gas utility margin:								
Natural gas operating revenue	119	103	16	16 %	103	99	4	4 %
Cost of natural gas purchased for resale	62	49	13	27	49	42	7	17
Natural gas utility margin	57	54	3	6 %	54	57	(3)	(5)%
Utility margin	490	484	6	1 %	484	502	(18)	(4)%
Operations and maintenance	172	190	(18)	(9)%	190	167	23	14 %
Depreciation and amortization	125	119	6	5	119	114	5	4
Property and other taxes	22	23	(1)	(4)	23	24	(1)	(4)
Operating income	$ 171	$ 152	$ 19	13 %	$ 152	$ 197	$ (45)	(23)%

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2019	2018	Change		2018	2017	Change	
Electric utility margin (in millions):								
Electric operating revenue	$ 770	$ 752	$ 18	2 %	$ 752	$ 713	$ 39	5 %
Cost of fuel and energy	337	322	15	5	322	268	54	20
Electric utility margin	$ 433	$ 430	$ 3	1 %	$ 430	$ 445	$ (15)	(3)%
GWhs sold:								
Residential	2,491	2,483	8	— %	2,483	2,492	(9)	— %
Commercial	2,973	2,998	(25)	(1)	2,998	2,954	44	1
Industrial	3,716	3,387	329	10	3,387	3,176	211	7
Other	16	16	—	—	16	16	—	—
Total fully bundled[1]	9,196	8,884	312	4	8,884	8,638	246	3
Distribution only service	1,629	1,516	113	7	1,516	1,394	122	9
Total retail	10,825	10,400	425	4	10,400	10,032	368	4
Wholesale	662	558	104	19	558	561	(3)	(1)
Total GWhs sold	11,487	10,958	529	5 %	10,958	10,593	365	3 %
Average number of retail customers (in thousands):								
Residential	304	300	4	1 %	300	295	5	2 %
Commercial	48	47	1	2	47	47	—	—
Total	352	347	5	1 %	347	342	5	1 %
Average per MWh:								
Revenue - retail fully bundled[1]	$ 76.72	$ 78.32	$ (1.60)	(2)%	$ 78.32	$ 76.90	$ 1.42	2 %
Revenue - wholesale	$ 48.54	$ 50.11	$ (1.57)	(3)%	$ 50.11	$ 50.29	$ (0.18)	— %
Cost of energy[2][3]	$ 31.81	$ 32.96	$ (1.15)	(3)%	$ 32.96	$ 27.35	$ 5.61	21 %
Heating degree days	4,728	4,450	278	6 %	4,450	4,523	(73)	(2)%
Cooling degree days	1,107	1,290	(183)	(14)%	1,290	1,401	(111)	(8)%
Sources of energy (GWhs)[3][4]:								
Natural gas	4,891	4,681	210	4 %	4,681	4,280	401	9 %
Coal	1,205	834	371	44	834	457	377	82
Renewables[5]	37	35	2	6	35	36	(1)	—
Total energy generated	6,133	5,550	583	11	5,550	4,773	777	16
Energy purchased	4,466	4,229	237	6	4,229	5,017	(788)	(16)
Total	10,599	9,779	820	8 %	9,779	9,790	(11)	— %

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost per MWh of energy includes only the cost of fuel associated with the generating facilities, purchased power and deferrals.

(3) The average cost per MWh of energy and sources of energy excludes 54 GWhs of coal and 183 GWhs of natural gas generated energy that is purchased at cost by related parties for the year ended December 31, 2018. There were no GWhs of coal or natural gas excluded for the years ended December 31, 2019 and 2017.

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

(5) Includes the Fort Churchill Solar Array which is under lease by Sierra Pacific.

Natural Gas Utility Margin

A comparison of key operating results related to natural gas utility margin is as follows for the years ended December 31:

	2019	2018	Change		2018	2017	Change	
Natural gas utility margin (in millions):								
Natural gas operating revenue	$ 119	$ 103	$ 16	16%	$ 103	$ 99	$ 4	4 %
Natural gas purchased for resale	62	49	13	27	49	42	7	17
Natural gas utility margin	$ 57	$ 54	$ 3	6%	$ 54	$ 57	$ (3)	(5)%
Natural gas sold (000's Dths):								
Residential	11,311	10,102	1,209	12%	10,102	10,291	(189)	(2)%
Commercial	5,783	5,128	655	13	5,128	5,153	(25)	—
Industrial	1,971	1,927	44	2	1,927	1,822	105	6
Total retail	19,065	17,157	1,908	11%	17,157	17,266	(109)	(1)%
Average number of retail customers (in thousands)	170	167	3	2%	167	164	3	2 %
Average revenue per retail Dth sold:	$ 6.24	$ 6.00	$ 0.24	4%	$ 6.00	$ 5.73	$ 0.27	5 %
Average cost of natural gas per retail Dth sold	$ 3.25	$ 2.86	$ 0.39	14%	$ 2.86	$ 2.43	$ 0.43	18 %
Heating degree days	4,728	4,450	278	6%	4,450	4,523	(73)	(2)%

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Electric utility margin increased $3 million, or 1%, for 2019 compared to 2018 primarily due to:

- $6 million of higher transmission and wholesale revenues; and
- $3 million of customer growth.

The increase in electric utility margin was offset by:

- $6 million in lower retail rates due to the tax rate reduction rider effective April 2018.

Natural gas utility margin increased $3 million, or 6%, for 2019 compared to 2018 primarily due to higher customer volumes mainly from the impacts of weather

Operations and maintenance decreased $18 million, or 9%, for 2019 compared to 2018 primarily due to lower political activity expenses and the impacts of adopting ASC 842 of $3 million, partially offset by higher generation plant costs of $3 million.

Depreciation and amortization increased $6 million, or 5%, for 2019 compared to 2018 primarily due to higher plant placed in service of $4 million and the impacts of adopting ASC 842 of $1 million.

Other income (expense) is unfavorable $10 million, or 33%, for 2019 compared to 2018 primarily due to higher non-service pension expense of $7 million and the impacts of adopting ASC 842 of $2 million.

Income tax expense decreased $2 million, or 7%, for 2019 compared to 2018. The effective tax rate was 21% in 2019 and 25% in 2018 and decreased due to lower nondeductible expenses.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Electric utility margin decreased $15 million or 3% for 2018 compared to 2017 primarily due to $18 million in lower retail rates from the tax rate reduction rider as a result of 2017 Tax Reform offset by $2 million of customer growth.

Natural gas utility margin decreased $3 million, or 5%, for 2018 compared to 2017 primarily due to lower retail rates from the tax rate reduction rider as a result of 2017 Tax Reform.

Operations and maintenance increased $23 million, or 14%, for 2018 compared to 2017 primarily due to increased political activity expenses.

Depreciation and amortization increased $5 million, or 4%, for 2018 compared to 2017 primarily due to higher plant placed in service.

Other income (expense) is favorable $3 million, or 9%, for 2018 compared to 2017 primarily due to lower pension expense.

Income tax expense decreased $25 million, or 45%, for 2018 compared to 2017. The effective tax rate was 25% in 2018 and 34% in 2017. The decrease in the effective tax rate is primarily due to 2017 Tax Reform, which reduced the United States federal corporate income tax rate from 35% to 21%, effective January 1, 2018, offset by an increase in nondeductible expenses.

Liquidity and Capital Resources

As of December 31, 2019, Sierra Pacific's total net liquidity was $277 million as follows (in millions):

Cash and cash equivalents	$	27
Credit facilities[(1)]		250
Total net liquidity	$	277
Credit facilities:		
Maturity dates		2022

(1) Refer to Note 7 of Notes to 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, 2019 and 2018 were $237 million and $275 million, respectively. The change was primarily due to higher payments for income taxes, an increase in fuel costs, higher payments for operating costs and decreased collections of customer advances, partially offset by lower contributions to the pension plan.

Net cash flows from operating activities for the years ended December 31, 2018 and 2017 were $275 million and $181 million, respectively. The change was due to a decrease in fuel costs and an increase in collections from customers from higher deferred energy rates, partially offset by higher operating costs, higher federal tax payments and higher contributions to the pension plan.

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, 2019 and 2018 were $(247) million and $(205) million, respectively. The change was primarily due to increased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2018 and 2017 were $(205) million and $(186) million, respectively. The change was primarily due to increased capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2019 and 2018 were $(34) million and $(2) million, respectively. The change was due to higher payments to repurchase long-term debt and dividends paid to NV Energy, Inc. of $46 million, partially offset by higher proceeds from the re-offering of previously repurchased long-term debt.

Net cash flows from financing activities for the years ended December 31, 2018 and 2017 were $(2) million and $(47) million, respectively. The change was due to higher dividends paid to NV Energy, Inc. of $45 million in 2017.

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, 2019, Sierra Pacific has financing authority from the PUCN consisting of the ability to issue long-term and short-term debt securities so long as the total amount of debt outstanding (excluding borrowings under Sierra Pacific's $250 million secured credit facility) does not exceed $1.6 billion as measured at the end of each calendar quarter. Sierra Pacific's revolving credit facility contains a financial maintenance covenant which Sierra Pacific was in compliance with as of December 31, 2019. 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, 2019, $4.2 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $1.4 billion of additional general and refunding mortgage securities as of December 31, 2019 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.

Long-Term Debt

In April 2019, Sierra Pacific purchased the following series of bonds that were held by the public: $30 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016C, due 2036; $25 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016D, due 2036; and $25 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016E, due 2036. Sierra Pacific purchased the Series 2016C, Series 2016D and Series 2016E bonds as required by the bond indentures.

In April 2019, Sierra Pacific entered into a re-offering of the following series of bonds: $30 million of its variable-rate tax-exempt Pollution Control Refunding Revenue Bonds, Series 2016B, due 2029; the Series 2016D bonds; the Series 2016E bonds; $75 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016F, due 2036; and $20 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016G, due 2036. The Series 2016B and Series 2016G bonds were offered at a fixed rate of 1.85%. The Series 2016D, Series 2016E and Series 2016F bonds were offered at a fixed rate of 2.05%. Sierra Pacific previously purchased the Series 2016B, Series 2016F and Series 2016G bonds on their date of issuance. Sierra Pacific holds the Series 2016C bonds and the bonds could be issued at a future date if required by future regulatory proceedings. Sierra Pacific used the net proceeds of the re-offering for general corporate purposes.

In June 2019, Sierra Pacific purchased the following series of bonds that were held by the public: $59 million of its fixed-rate tax-exempt Gas Facilities Refunding Revenue Bonds, Series 2016A, due 2031 and $20 million of its fixed-rate tax-exempt Humboldt County Pollution Control Refunding Revenue Bonds, Series 2016A, due 2029. Sierra Pacific holds these bonds and the bonds could be issued at a future date if required by future regulatory proceedings.

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		
	2017	2018	2019	2020	2021	2022
Generation development	$ —	$ —	$ —	$ —	$ —	$ 5
Distribution	88	162	164	91	98	118
Transmission system investment	12	5	13	18	18	35
Operating and other	86	34	68	70	60	29
Total	$ 186	$ 201	$ 245	$ 179	$ 176	$ 187

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 financial condition. The following table summarizes Sierra Pacific's material contractual cash obligations as of December 31, 2019 (in millions):

	Payments Due by Periods				
	2020	2021 - 2022	2023 - 2024	2025 and Thereafter	Total
Long-term debt	$ —	$ —	$ 250	$ 887	$ 1,137
Interest payments on long-term debt[1]	41	82	74	292	489
ON Line finance lease liability	—	1	2	17	20
Interest payments on ON Line finance lease liability[1]	2	3	2	18	25
Operating and finance lease liabilities	4	7	4	27	42
Interest payments on operating and finance lease liabilities[1]	2	4	4	11	21
Fuel and capacity contract commitments[1][2]	260	312	167	863	1,602
Fuel and capacity contract commitments (not commercially operable)[1][2]	1	52	83	921	1,057
Easements[1]	2	4	4	30	40
Asset retirement obligations	—	—	—	14	14
Maintenance, service and other contracts[1]	11	15	3	9	38
Total contractual cash obligations	$ 323	$ 480	$ 593	$ 3,089	$ 4,485

(1) Not reflected on the Balance Sheets.

(2) Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated.

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 7) and asset retirement obligations (Note 11), 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 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 climate change, RPS, air and water quality, emissions performance standards, 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.

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, 2019, the applicable credit ratings obtained from 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, 2019, Sierra Pacific would have been required to post $21 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 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 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 Sierra Pacific's methods, judgments and assumptions used in the preparation of the 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 Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its 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 $295 million and total regulatory liabilities were $538 million as of December 31, 2019. Refer to Sierra Pacific's Note 6 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2019, 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 commissions. 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 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 financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Statements of Operations. Refer to Sierra Pacific's Note 9 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's income taxes.

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 $63 million as of December 31, 2019. 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 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 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 all of 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 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 7 and 8 of Notes to 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, 2019 and 2018, Sierra Pacific had short- and long-term variable-rate obligations totaling $- million and $80 million, respectively, 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 annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2019 and 2018.

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, 2019, Sierra Pacific's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Sierra Pacific Power Company ("Sierra Pacific") as of December 31, 2019 and 2018, the related statements of operations, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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 21, 2020
We have served as Sierra Pacific's auditor since 1996.

SIERRA PACIFIC POWER COMPANY
BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2019	2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27	$ 71
Trade receivables, net	109	100
Income taxes receivable	14	—
Inventories	57	52
Regulatory assets	12	7
Other current assets	20	33
Total current assets	239	263
Property, plant and equipment, net	3,075	2,947
Regulatory assets	283	314
Other assets	74	45
Total assets	$ 3,671	$ 3,569
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 103	$ 116
Accrued interest	14	13
Accrued property, income and other taxes	12	14
Regulatory liabilities	49	18
Customer deposits	21	18
Other current liabilities	21	18
Total current liabilities	220	197
Long-term debt	1,135	1,120
Regulatory liabilities	489	491
Deferred income taxes	347	331
Other long-term liabilities	160	166
Total liabilities	2,351	2,305
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	—	—
Additional paid-in capital	1,111	1,111
Retained earnings	210	153
Accumulated other comprehensive loss, net	(1)	—
Total shareholder's equity	1,320	1,264
Total liabilities and shareholder's equity	$ 3,671	$ 3,569

The accompanying notes are an integral part of the financial statements.

SIERRA PACIFIC POWER COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2019	2018	2017
Operating revenue:			
Regulated electric	$ 770	$ 752	$ 713
Regulated natural gas	119	103	99
Total operating revenue	889	855	812
Operating expenses:			
Cost of fuel and energy	337	322	268
Cost of natural gas purchased for resale	62	49	42
Operations and maintenance	172	190	167
Depreciation and amortization	125	119	114
Property and other taxes	22	23	24
Total operating expenses	718	703	615
Operating income	171	152	197
Other income (expense):			
Interest expense	(48)	(44)	(43)
Allowance for borrowed funds	1	1	2
Allowance for equity funds	3	4	3
Other, net	4	9	5
Total other income (expense)	(40)	(30)	(33)
Income before income tax expense	131	122	164
Income tax expense	28	30	55
Net income	$ 103	$ 92	$ 109

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

SIERRA PACIFIC POWER COMPANY
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, 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
Net income	—	—	—	92	—	92
Other equity transactions	—	—	—	(1)	1	—
Balance, December 31, 2018	1,000	—	1,111	153	—	1,264
Net income	—	—	—	103	—	103
Dividends declared	—	—	—	(46)	—	(46)
Other equity transactions	—	—	—	—	(1)	(1)
Balance, December 31, 2019	1,000	$ —	$ 1,111	$ 210	$ (1)	$ 1,320

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

SIERRA PACIFIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31, 2019	2018	2017
Cash flows from operating activities:			
Net income	$ 103	$ 92	$ 109
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss on nonrecurring items	1	—	—
Depreciation and amortization	125	119	114
Allowance for equity funds	(3)	(4)	(4)
Changes in regulatory assets and liabilities	25	42	17
Deferred income taxes and amortization of investment tax credits	9	7	55
Deferred energy	15	9	(20)
Amortization of deferred energy	(2)	(10)	(47)
Other, net	(1)	—	(4)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(6)	3	4
Inventories	(5)	(4)	(3)
Accrued property, income and other taxes	(16)	3	1
Accounts payable and other liabilities	(8)	18	(41)
Net cash flows from operating activities	237	275	181
Cash flows from investing activities:			
Capital expenditures	(248)	(205)	(186)
Proceeds from sale of assets	1	—	—
Net cash flows from investing activities	(247)	(205)	(186)
Cash flows from financing activities:			
Proceeds from long-term debt	125	—	—
Repayments of long-term debt	(109)	—	—
Dividends paid	(46)	—	(45)
Other, net	(4)	(2)	(2)
Net cash flows from financing activities	(34)	(2)	(47)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(44)	68	(52)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	76	8	60
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 32	$ 76	$ 8

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

(1) Organization and Operations

Sierra Pacific Power Company ("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 Presentation

The Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2019, 2018 and 2017.

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; 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 Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its 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 current assets and other assets on the 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 collectability 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. As of December 31, 2019 and 2018, the allowance for doubtful accounts was $2 million and is included in trade receivables, net on the Balance Sheets.

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 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 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 $49 million and $44 million as of December 31, 2019 and 2018, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $8 million and $8 million as of December 31, 2019 and 2018, 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 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 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 2019 and 2018 was 6.65% for electric, 5.75% and 5.74% for natural gas, respectively, and 6.55% for common facilities.

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 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 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 Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2019, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

Lessee

Sierra Pacific has non-cancelable operating leases primarily for transmission and delivery assets, generating facilities, vehicles and office equipment and finance leases consisting primarily of transmission assets, generating facilities and vehicles. These leases generally require Sierra Pacific to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Sierra Pacific does not include options in its lease calculations unless there is a triggering event indicating Sierra Pacific is reasonably certain to exercise the option. Sierra Pacific's accounting policy is to not recognize lease obligations and corresponding right-of-use assets for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with ASC Topic 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

Sierra Pacific's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

Sierra Pacific's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly. The right-of-use assets and lease liabilities for finance leases as of December 31, 2018 have been reclassified from property, plant and equipment, net and current portion of long-term and long-term debt, respectively, to conform to the current period presentation.

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. Changes in deferred income tax assets and liabilities that are associated with 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 commissions. 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 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 financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Statements of Operations.

Revenue Recognition

Sierra Pacific uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Sierra Pacific expects to be entitled in exchange for those goods or services. 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 Statements of Operations.

Substantially all of Sierra Pacific's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of revenue recognized in accordance with ASC 842, "Leases" and amounts not considered Customer Revenue within Accounting Standards Codification ("ASC") 606, "Revenue from Contracts with Customers."

Revenue recognized is equal to what Sierra Pacific has the right to invoice as it corresponds directly with the value to the customer of Sierra Pacific's performance to date and includes billed and unbilled amounts. As of December 31, 2019 and 2018, trade receivables, net on the Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $63 million and $57 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. 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.

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 February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("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 on 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. Following the issuance of ASU No. 2016-02, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2016-02 but did not change the core principle of the guidance. Sierra Pacific has elected to utilize various practical expedients available to adopt ASU No. 2016-02, including (1) the package of three not requiring a reassessment of (i) whether any expired or existing contracts are or contain leases; (ii) the lease classification for any expired or existing leases; and (iii) initial direct costs for any existing leases; (2) using hindsight in determining the lease term; and (3) not requiring a reassessment of whether existing or expired land easements that were not previously accounted for as leases under ASC Topic 840 are or contain a lease under ASC Topic 842. Sierra Pacific adopted this guidance for all applicable contracts in-effect as of January 1, 2019 under a modified retrospective method and the adoption did not have a cumulative effect impact at the date of initial adoption.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2019	2018
Utility plant:			
Electric generation	25 - 60 years	$ 1,133	$ 1,132
Electric distribution	20 - 100 years	1,669	1,568
Electric transmission	50 - 100 years	840	812
Electric general and intangible plant	5 - 70 years	178	185
Natural gas distribution	35 - 70 years	417	403
Natural gas general and intangible plant	5 - 70 years	14	14
Common general	5 - 70 years	338	321
Utility plant		4,589	4,435
Accumulated depreciation and amortization		(1,629)	(1,583)
Utility plant, net		2,960	2,852
Other non-regulated, net of accumulated depreciation and amortization	70 years	2	5
Plant, net		2,962	2,857
Construction work-in-progress		113	90
Property, plant and equipment, net		$ 3,075	$ 2,947

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, 2019, 2018 and 2017 was 3.1%, 3.1% and 3.0%, respectively. Sierra Pacific is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate review filings.

Construction work-in-progress is related to the construction of regulated assets.

(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 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, 2019 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50%	$ 390	$ 271	$ —
ON Line Transmission Line	1	8	1	—
Valmy Transmission	50	4	2	—
Total		$ 402	$ 274	$ —

(5) Leases

The following table summarizes Sierra Pacific's leases recorded on the Balance Sheet (in millions):

	As of December 31, 2019
Right-of-use assets:	
Operating leases	$ 17
Finance leases	43
Total right-of-use assets	$ 60
Lease liabilities:	
Operating leases	$ 17
Finance leases	45
Total lease liabilities	$ 62

The following table summarizes Sierra Pacific's lease costs (in millions):

	Year Ended December 31, 2019
Variable	$ 69
Operating	1
Finance:	
Amortization	2
Interest	2
Total lease costs	$ 74
Weighted-average remaining lease term (years):	
Operating leases	26.3
Finance leases	20.9
Weighted-average discount rate:	
Operating leases	5.0%
Finance leases	7.1%

The following table summarizes Sierra Pacific's supplemental cash flow information relating to leases (in millions):

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ (3)
Operating cash flows from finance leases	(3)
Financing cash flows from finance leases	(3)
Right-of-use assets obtained in exchange for lease liabilities:	
Finance leases	$ 5

Sierra Pacific has the following remaining lease commitments as of (in millions):

	December 31, 2019		
	Operating	Finance	Total
2020	$ 2	$ 6	$ 8
2021	2	6	8
2022	1	6	7
2023	1	6	7
2024	1	5	6
Thereafter	26	46	72
Total undiscounted lease payments	33	75	108
Less - amounts representing interest	(16)	(30)	(46)
Lease liabilities	$ 17	$ 45	$ 62

	December 31, 2018[(1)]		
	Operating	Capital	Total
2019	$ 2	$ 6	$ 8
2020	2	4	6
2021	2	5	7
2022	1	4	5
2023	1	4	5
Thereafter	28	47	75
Total undiscounted lease payments	$ 36	$ 70	$ 106

(1) Amounts included for comparability and accounted for in accordance with ASC Topic 840, "Leases".

Operating and Finance Lease Obligations

Sierra Pacific's operating and finance lease obligations consist mainly of ON Line and Truckee-Carson Irrigation District ("TCID"). ON Line was placed in-service on December 31, 2013. Sierra Pacific and Nevada Power, collectively the ("Nevada Utilities"), entered into a long-term transmission use agreement, in which the Nevada Utilities have a 25% interest and Great Basin Transmission South, LLC has a 75% interest. 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. In December 2019, the PUCN ordered the Nevada Utilities to complete the procedures changing the ownership split to 75% for Nevada Power and 25% for Sierra Pacific, effective January 1, 2020. The term of the lease is 41 years with the agreement ending December 31, 2054. In 1999, Sierra Pacific entered into a 50-year agreement with TCID to lease electric distribution facilities. Total finance lease obligations of $35 million and $21 million were included on the Consolidated Balance Sheets as of December 31, 2019 and 2018, respectively, for these leases. See Note 2 for further discussion of Sierra Pacific's remaining lease obligations.

(6) Regulatory Matters

Regulatory Assets

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

	Weighted Average Remaining Life	2019	2018
Employee benefit plans[(1)]	8 years	$ 107	$ 132
Merger costs from 1999 merger	27 years	71	74
Abandoned projects	7 years	24	29
Deferred Operating Costs	12 years	23	15
Losses on reacquired debt	15 years	17	19
Other	Various	53	52
Total regulatory assets		$ 295	$ 321
Reflected as:			
Current assets		$ 12	$ 7
Noncurrent assets		283	314
Total regulatory assets		$ 295	$ 321

(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.

Sierra Pacific had regulatory assets not earning a return on investment of $168 million and $190 million as of December 31, 2019 and 2018, 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 Liabilities

Regulatory liabilities represent amounts that are expected to be returned to customers in future periods. Sierra Pacific's regulatory liabilities reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2019	2018
Deferred income taxes[(1)]	Various	$ 263	$ 270
Cost of removal[(2)]	38 years	217	210
Other	Various	58	29
Total regulatory liabilities		$ 538	$ 509
Reflected as:			
Current liabilities		$ 49	$ 18
Noncurrent liabilities		489	491
Total regulatory liabilities		$ 538	$ 509

(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.

(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.

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 Statements of Operations but rather is deferred and recorded as a regulatory asset on the 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 2019, Sierra Pacific filed an electric regulatory rate review with the PUCN. The filing supported an annual revenue increase of $5 million but requested an annual revenue reduction of $5 million. In September 2019, Sierra Pacific filed an all-party settlement for the electric regulatory rate review. The settlement resolves all cost of capital and revenue requirement issues and provides for an annual revenue reduction of $5 million and requires Sierra Pacific to share 50% of regulatory earnings above 9.7% with its customers. The rate design portion of the regulatory rate review was not a part of the settlement and a hearing on rate design was held in November 2019. In December 2019, the PUCN issued an order approving the stipulation but made some adjustments to the methodology for the weather normalization component of historical sales in rates, which resulted in an annual revenue reduction of $3 million. The new rates were effective January 1, 2020. In January 2020, Sierra Pacific filed a petition for rehearing challenging the PUCN's adjustments to the weather normalization methodology. In February 2020, the PUCN issued an order granting the petition for rehearing.

2017 Tax Reform

In February 2018, Sierra Pacific made filings with the PUCN proposing a tax rate reduction rider for the lower annual income tax expense anticipated to result from 2017 Tax Reform for 2018 and beyond. In March 2018, the PUCN issued an order approving the rate reduction proposed by Sierra Pacific. The new rates were effective April 1, 2018. The order extended the procedural schedule to allow parties additional discovery relevant to 2017 Tax Reform and a hearing was held in July 2018. In September 2018, the PUCN issued an order directing Sierra Pacific to record the amortization of any excess protected accumulated deferred income tax arising from the 2017 Tax Reform as a regulatory liability effective January 1, 2018. Subsequently, Sierra Pacific filed a petition for reconsideration relating to the amortization of protected excess accumulated deferred income tax balances resulting from the 2017 Tax Reform. In November 2018, the PUCN issued an order granting reconsideration and reaffirming the September 2018 order. In December 2018, Sierra Pacific filed a petition for judicial review. In January 2019, intervening parties filed statements of intent to participate in the petition for judicial review. Sierra Pacific has filed opening briefs and the intervening parties have filed answering briefs. The hearing occurred in January 2020 and a ruling is expected in the first half of 2020.

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. When Sierra Pacific's regulatory earned rate of return for a calendar year exceeds the regulatory rate of return used to set base tariff general rates, it is obligated to refund energy efficiency implementation revenue previously collected for that year. In March 2019, Sierra Pacific filed an application to reset the EEIR and EEPR and to refund the EEIR revenue received in 2018, including carrying charges. In August 2019, the PUCN issued an order accepting a stipulation to reset the rates as filed effective October 1, 2019. The EEIR liability for Sierra Pacific is $2 million and $2 million, which is included in current regulatory liabilities on the Balance Sheets as of December 31, 2019 and 2018, respectively.

(7) Credit Facility

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

	2019	2018
Credit facilities	$ 250	$ 250
Less - Water Facilities Refunding Revenue Bond support	—	(80)
Net credit facilities	$ 250	$ 170

Sierra Pacific has a $250 million secured credit facility expiring in June 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 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, 2019 and 2018, 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 debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

(8) Long-Term Debt

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	2019	2018
General and refunding mortgage securities:			
3.375% Series T, due 2023	$ 250	$ 249	$ 249
2.600% Series U, due 2026	400	396	396
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	—	—	20
1.850% Pollution Control Series 2016B, due 2029 (1)	30	29	—
1.500% Gas Facilities Series 2016A, due 2031	—	—	58
3.000% Gas and Water Series 2016B, due 2036 (2)	60	62	62
1.850% Water Facilities Series 2016C, due 2036 (3)	—	—	30
2.050% Water Facilities Series 2016D, due 2036 (1) (4)	25	25	25
2.050% Water Facilities Series 2016E, due 2036 (1) (4)	25	25	25
2.050% Water Facilities Series 2016F, due 2036 (1)	75	74	—
1.850% Water Facilities Series 2016G, due 2036 (1)	20	20	—
Total long-term debt	$ 1,137	$ 1,135	$ 1,120
Reflected as -			
Long-term debt		$ 1,135	$ 1,120

(1) Subject to mandatory purchase by Sierra Pacific in April 2022 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.

(3) Bond was purchased by Sierra Pacific during 2019. As of December 31, 2018 the bond variable interest rate was 1.750% to 1.820%.

(4) Bonds were purchased by Sierra Pacific during 2019 and re-offered at a fixed interest rate. As of December 31, 2018 the bonds variable interest rate was 1.750% to 1.820%.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2020 and thereafter, are as follows (in millions):

2023	$ 250
2025 and thereafter	887
Total	1,137
Unamortized premium, discount and debt issuance cost	(2)
Total	$ 1,135

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, 2019, approximately $4.2 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

(9) Income Taxes

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

	2019	2018	2017
Current – Federal	$ 19	$ 23	$ —
Deferred – Federal	10	7	56
Uncertain tax positions	—	1	—
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 28	$ 30	$ 55

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:

	2019	2018	2017
Federal statutory income tax rate	21%	21%	35%
Non-deductible expenses	—	4	—
Effect of tax rate change	—	—	(1)
Effective income tax rate	21%	25%	34%

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

		2019		2018
Deferred income tax assets:				
Regulatory liabilities	$	70	$	70
Employee benefit plans		6		10
Operating and finance leases		13		8
Customer Advances		9		8
Other		6		6
Total deferred income tax assets		104		102
Deferred income tax liabilities:				
Property related items		(370)		(346)
Regulatory assets		(62)		(73)
Operating and finance leases		(13)		(8)
Other		(6)		(6)
Total deferred income tax liabilities		(451)		(433)
Net deferred income tax liability	$	(347)	$	(331)

The United States Internal Revenue Service has closed its examination of NV Energy's consolidated income tax returns through December 31, 2008, and the statute of limitations has expired for NV Energy's consolidated income tax returns through the short year ended December 19, 2013. The statute of limitations expiring may not preclude the Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the examination is not closed.

(10) Employee Benefit Plans

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 did not make any contributions to the Qualified Pension Plan for the year ended December 31, 2019 and contributed $6 million and $1 million to the Qualified Pension Plan for the years ended December 31, 2018 and 2017, respectively. Sierra Pacific contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2019, 2018 and 2017. Sierra Pacific contributed $- million, $6 million and $4 million to the Other Postretirement Plans for the years ended December 31, 2019, 2018 and 2017, 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 Balance Sheets and consist of the following as of December 31(in millions):

		2019		2018
Qualified Pension Plan -				
Other long-term liabilities	$	4	$	19
Non-Qualified Pension Plans:				
Other current liabilities		1		1
Other long-term liabilities		8		7
Other Postretirement Plans -				
Other long-term liabilities		7		13

(11) 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 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 $217 million and $210 million as of December 31, 2019 and 2018, respectively.

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

	2019	2018
Asbestos	$ 5	$ 5
Evaporative ponds and dry ash landfills	2	2
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):

	2019	2018
Beginning balance	$ 10	$ 10
Accretion	—	—
Ending balance	$ 10	$ 10
Reflected as -		
Other long-term liabilities	$ 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 Balance Sheets.

(12) 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 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 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, 2019:				
Assets - money market mutual funds[1]	$ 25	$ —	$ —	$ 25
Liabilities - commodity derivatives	$ —	$ —	$ (1)	$ (1)
As of December 31, 2018:				
Assets:				
Commodity derivatives	$ —	$ —	$ 2	$ 2
Money market mutual funds[1]	45	—	—	45
	$ 45	$ —	$ 2	$ 47

(1) Amounts are included in cash and cash equivalents on the 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 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):

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,135	$ 1,258	$ 1,120	$ 1,167

(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 financial results. Sierra Pacific 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.

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2019 are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 260	$ 198	$ 114	$ 84	$ 83	$ 863	$ 1,602
Fuel and capacity contract commitments (not commercially operable)	1	11	41	41	42	921	1,057
Easements	2	2	2	2	2	30	40
Maintenance, service and other contracts	11	8	7	2	1	9	38
Total commitments	$ 274	$ 219	$ 164	$ 129	$ 128	$ 1,823	$ 2,737

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 2020 to 2044. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Sierra Pacific's lease commitments.

Coal and Natural Gas

Sierra Pacific has a long-term contract for the transport of coal that expires in 2021. Additionally, gas transportation contracts expire from 2020 to 2046 and the gas supply contracts expire from 2020 to 2021.

Fuel and Capacity Contract Commitments - Not Commercially Operable

Sierra Pacific 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.

Easements

Sierra Pacific has non-cancelable easements for land. Operating and maintenance expense on non-cancelable easements totaled $2 million for the years-ended December 31, 2019, 2018 and 2017.

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 2020 to 2039.

(14) Revenues from Contracts with Customers

The following table summarizes Sierra Pacific's revenue by customer class, including a reconciliation to Sierra Pacific's reportable segment information included in Note 17, for the years ended December 31 (in millions):

	2019			2018		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Customer Revenue:						
Retail:						
Residential	$ 268	$ 76	$ 344	$ 267	$ 67	$ 334
Commercial	245	30	275	246	25	271
Industrial	186	10	196	177	8	185
Other	6	1	7	6	1	7
Total fully bundled	705	117	822	696	101	797
Distribution only service	4	—	4	4	—	4
Total retail	709	117	826	700	101	801
Wholesale, transmission and other	57	—	57	48	—	48
Total Customer Revenue	766	117	883	748	101	849
Other revenue	4	2	6	4	2	6
Total revenue	$ 770	$ 119	$ 889	$ 752	$ 103	$ 855

(15) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

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 cash and cash equivalents as of December 31, 2019 and December 31, 2018, consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and December 31, 2018, as presented in the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Balance Sheets (in millions):

	As of	
	December 31, 2019	December 31, 2018
Cash and cash equivalents	$ 27	$ 71
Restricted cash and cash equivalents included in other current assets	5	5
Total cash and cash equivalents and restricted cash and cash equivalents	$ 32	$ 76

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

	2019	2018	2017
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 41	$ 41	$ 40
Income taxes paid	$ 37	$ 19	$ —
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 18	$ 15	$ 10

(16) 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 years ended December 31, 2019, 2018 and 2017.

Sierra Pacific provided electricity to Nevada Power of $25 million, $28 million and $21 million for the years ended December 31, 2019, 2018 and 2017, respectively. Receivables associated with these transactions were $1 million as of December 31, 2019 and 2018. Sierra Pacific purchased electricity from Nevada Power of $84 million, $91 million and $104 million for the years ended December 31, 2019, 2018 and 2017, respectively. Payables associated with these transactions were $5 million and $6 million as of December 31, 2019 and 2018, 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 $4 million, $4 million and $5 million for the years ending December 31, 2019, 2018 and 2017, respectively. Sierra Pacific provided services to Nevada Power of $14 million, $15 million, and $17 million for the years ended December 31, 2019, 2018 and 2017, respectively. Nevada Power provided services to Sierra Pacific of $26 million, $28 million, and $27 million for the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019 and 2018, Sierra Pacific's Balance Sheets included amounts due to NV Energy of $15 million. There were no receivables due from NV Energy as of December 31, 2019 and 2018. As of December 31, 2019 and 2018, Sierra Pacific's Balance Sheets included payables due to Nevada Power of $3 million and $5 million, respectively. There were no receivables due from Nevada Power as of December 31, 2019 and 2018.

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. Federal income taxes receivable from NV Energy were $14 million as of December 31, 2019 and federal income taxes payable to NV Energy were $3 million as of December 31, 2018. Sierra Pacific made cash payments of $37 million and $19 million for federal income taxes for the year ended December 31, 2019 and 2018, respectively. No cash payments were made for federal income taxes for the year ended December 31, 2017.

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.

(17) 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.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2019	2018	2017
Operating revenue:			
Regulated electric	$ 770	$ 752	$ 713
Regulated natural gas	119	103	99
Total operating revenue	$ 889	$ 855	$ 812
Operating income:			
Regulated electric	$ 150	$ 136	$ 175
Regulated natural gas	21	16	22
Total operating income	171	152	197
Interest expense	(48)	(44)	(43)
Allowance for borrowed funds	1	1	2
Allowance for equity funds	3	4	3
Other, net	4	9	5
Income before income tax expense	$ 131	$ 122	$ 164

	As of December 31,		
	2019	2018	2017
Assets			
Regulated electric	$ 3,319	$ 3,177	$ 3,103
Regulated natural gas	308	314	300
Regulated common assets(1)	44	78	10
Total assets	$ 3,671	$ 3,569	$ 3,413

(1) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments.

(18) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019
Regulated electric operating revenue	$ 182	$ 172	$ 232	$ 184
Regulated natural gas operating revenue	37	22	16	44
Operating income	37	27	67	40
Net income	22	14	44	23

	Three-Month Periods Ended			
	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
Regulated electric operating revenue	$ 181	$ 169	$ 225	$ 177
Regulated natural gas operating revenue	41	19	14	29
Operating income	47	19	56	30
Net income	34	7	35	16

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, 2019 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, 2019, 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, 2019.

Berkshire Hathaway Energy Company	PacifiCorp	MidAmerican Funding, LLC
February 21, 2020	February 21, 2020	February 21, 2020
MidAmerican Energy Company	Nevada Power Company	Sierra Pacific Power Company
February 21, 2020	February 21, 2020	February 21, 2020

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 January 31, 2020, with respect to the current directors and executive officers of PacifiCorp:

WILLIAM J. FEHRMAN, 59, 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 January 2018 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, 53, President and Chief Executive Officer of Pacific Power and director since 2015. Mr. Bird was Senior Vice President, Commercial and Trading, of PacifiCorp from 2007 to 2014. Mr. Bird joined BHE in 1998 and has significant operational, public policy and leadership experience in the energy industry, including expertise in energy supply management, resource acquisition and federal and state regulatory matters.

GARY W. HOOGEVEEN, 51, President and Chief Executive Officer of Rocky Mountain Power since November 2018. Prior to his current position Mr. Hoogeveen served as Senior Vice President and Chief Commercial Officer of Rocky Mountain Power since November 2014 and President and CEO of Kern River Gas Transmission Company from 2010 to 2014. He joined Kern River after serving as Vice President of Customer Service and Business Development for Northern Natural Gas Company. Prior to joining Northern Natural Gas, he held various management positions at Berkshire Hathaway Energy.

NIKKI L. KOBLIHA, 47, 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, 53, 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, 50, 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, 2019, 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. William J. Fehrman, 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. Fehrman'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.

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. 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 2019, base salaries for all NEOs, other than the Chairman and CEO, increased on average by 3.72% effective December 26, 2018, 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 2019. 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. No cash performance awards were granted to the NEO's in 2019.

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 finalized in the first quarter of the following year. 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]
William J. Fehrman[5][6]	2019	$ —	$ —	$ —	$ —	$ —
Chairman of the Board of Directors	2018	—	—	—	—	—
and Chief Executive Officer	2017	—	—	—	—	—
Stefan A. Bird	2019	365,000	1,286,958	10,152	31,845	1,693,955
President and Chief Executive	2018	355,000	1,058,696	29,549	31,633	1,474,878
Officer, Pacific Power	2017	346,000	1,116,105	9,480	30,965	1,502,550
Gary W. Hoogeveen[7]	2019	350,000	964,837	—	32,731	1,347,568
President and Chief Executive	2018	315,570	898,733	—	32,484	1,246,787
Officer, Rocky Mountain Power	2017	—	—	—	—	—
Nikki L. Kobliha	2019	239,571	243,289	33,825	31,391	548,076
Vice President, Chief Financial	2018	224,510	190,045	—	30,804	445,359
Officer and Treasurer	2017	217,079	122,400	18,304	30,415	388,198

(1) Consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs and the vesting of LTIP awards and associated vested earnings. The breakout for 2019 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings	Total
Stefan A. Bird	$ 550,000	$ —	$ 645,000	$ 91,958	$ 736,958
Gary W. Hoogeveen	450,000	—	352,410	162,427	514,837
Nikki L. Kobliha	115,274	—	102,125	25,890	128,015

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 2019, the gross award was subjectively determined at the discretion of the BHE Chairman and PacifiCorp's 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. Hoogeveen for whom PacifiCorp also includes an amount paid for 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) On January 10, 2018, Mr. William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

(6) Mr. Fehrman receives no direct compensation from PacifiCorp. PacifiCorp reimburses BHE for the cost of Mr. Fehrman'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 2019, PacifiCorp reimbursed BHE $260,538 for the cost of Mr. Fehrman's time spent on matters supporting PacifiCorp pursuant to the intercompany administrative services agreement.

(7) On June 1, 2018, Mr. Hoogeveen was named Rocky Mountain Power's president effective June 1, 2018 and Rocky Mountain Power's chief executive officer effective November 28, 2018.

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, 2019:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits (1)
William J. Fehrman	n/a	n/a	n/a
Stefan A. Bird	Retirement	10 years	$ 216,926
Gary W. Hoogeveen	n/a	n/a	n/a
Nikki L. Kobliha	Retirement	12 years	145,974

(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, 2019, 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 3.25%; 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, 2013, 2014 and 2015 rates were used for MP-2016, MP-2017, MP-2018 and MP-2019, respectively and generational mortality improvements from 2015 forward were based on the custom RPEC 2014 v2019 model; a lump sum interest rate of 3.25%; and lump sum mortality using the unisex tables set forth in IRC 417(e)(3) for the upcoming fiscal year with mortality improvements determined using MP-2018.

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 and Mr. Hoogeveen elected the equivalent fixed 401(k) contribution option and, therefore, no longer receive pay credits in the Retirement Plan. In 2017, the Retirement Plan was frozen for the remainder of the non-union employees (which includes Mr. Bird) 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, 2019:

Name	Executive contributions in 2019[(1)]	Registrant contributions in 2019	Aggregate earnings/losses in 2019	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2019
William J. Fehrman	$ —	$ —	$ —	$ —	$ —
Stefan A. Bird	—	—	—	—	—
Gary W. Hoogeveen	718,124	—	378,371	—	2,524,570
Nikki L. Kobliha	—	—	4,351	—	51,360

(1) The executive contribution amount shown for Mr. Hoogeveen represents a deferral of $450,000 of his 2019 compensation and a deferral of $268,124 of his 2016 LTIP award which was deferred in 2019. $154,351 of the deferred 2016 LTIP award is included in the 2019 total compensation reported for him in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2019.

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.

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. Fehrman. 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, 2019 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	$ —	$ 24,016
Death and Disability	1,085,034	24,016
Gary W. Hoogeveen:		
Retirement, Voluntary and Involuntary With or Without Cause	—	n/a
Death and Disability	649,177	n/a
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	—
Death and Disability	237,110	—

(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.

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. Fehrman, Bird, Hoogeveen, and Ms. Kobliha for their services as executive officers of PacifiCorp is described above.

Compensation Committee Interlocks and Insider Participation

Mr. Fehrman is 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 January 31, 2020, owns 90.9% 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 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 January 31, 2020:

	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	—	—	—	—	—	—
Stefan A. Bird	—	—	—	—	—	—
Patrick J. Goodman	—	—	5	*	786	*
Natalie L. Hocken	—	—	—	—	—	—
Nikki L. Kobliha	—	—	—	—	—	—
Gary W. Hoogeveen	—	—	—	—	1,073	*
All executive officers and directors as a group (6 persons)	—	—	5	*	1,859	*

* 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 21 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(1)	PacifiCorp	MidAmerican Funding(1)	MidAmerican Energy	Nevada Power	Sierra Pacific
2019						
Audit fees(2)	$ 9.7	$ 1.5	$ 1.4	$ 1.2	$ 0.9	$ 0.9
Audit-related fees(3)	0.9	0.4	0.2	0.2	—	—
Tax fees(4)	0.1	—	—	—	—	—
Total	$ 10.7	$ 1.9	$ 1.6	$ 1.4	$ 0.9	$ 0.9
2018						
Audit fees(2)	$ 9.6	$ 1.6	$ 1.2	$ 1.1	$ 0.9	$ 0.9
Audit-related fees(3)	0.8	0.3	0.2	0.2	—	—
Tax fees(4)	0.1	—	—	—	—	—
Total	$ 10.5	$ 1.9	$ 1.4	$ 1.3	$ 0.9	$ 0.9

(1) The reported fees for Berkshire Hathaway Energy include those fees reported for PacifiCorp, MidAmerican Funding, Nevada Power and Sierra Pacific while the reported fees for MidAmerican Funding include those fees reported for MidAmerican Energy.

(2) 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.

(3) 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.

(4) 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

The financial statements of all Registrants are included in their respective Item 8 of this Form 10-K.	89

(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.

(3) Management contracts or compensatory plans are identified by an asterisk in the Exhibit Index filed as part of this Annual Report.	426

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report.	426

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

MHC Inc. Consolidated Financial Statements	411

Item 16. Form 10-K Summary

None.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13	$ 9
Accounts receivable - affiliate	87	100
Notes receivable - affiliate	181	156
Income tax receivable	3	103
Other current assets	8	15
Total current assets	292	383
Investments in subsidiaries	40,204	36,602
Other investments	1,300	1,579
Goodwill	1,221	1,221
Other assets	695	546
Total assets	$ 43,712	$ 40,331
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 194	$ 183
Notes payable - affiliate	240	328
Short-term debt	1,590	983
Current portion of BHE senior debt	350	—
Total current liabilities	2,374	1,494
BHE senior debt	8,231	8,577
BHE junior subordinated debentures	100	100
Notes payable - affiliate	2	1
Other long-term liabilities	530	543
Total liabilities	11,237	10,715
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,389	6,371
Long-term income tax receivable	(530)	(457)
Retained earnings	28,296	25,624
Accumulated other comprehensive loss, net	(1,706)	(1,945)
Total BHE shareholders' equity	32,449	29,593
Noncontrolling interest	26	23
Total equity	32,475	29,616
Total liabilities and equity	$ 43,712	$ 40,331

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

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Operating expenses:			
General and administration	$ 49	$ 21	$ 55
Depreciation and amortization	5	4	4
Total operating expenses	54	25	59
Operating loss	(54)	(25)	(59)
Other income (expense):			
Interest expense	(452)	(438)	(475)
Other, net	(271)	(537)	(369)
Total other income (expense)	(723)	(975)	(844)
Loss before income tax benefit and equity income	(777)	(1,000)	(903)
Income tax benefit	(312)	(513)	(335)
Equity income	3,419	3,058	3,441
Net income	2,954	2,571	2,873
Net income attributable to noncontrolling interest	3	3	3
Net income attributable to BHE shareholders	$ 2,951	$ 2,568	$ 2,870

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

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2019	2018	2017
Net income	$ 2,954	$ 2,571	$ 2,873
Other comprehensive income (loss), net of tax	239	(462)	1,113
Comprehensive income	3,193	2,109	3,986
Comprehensive income attributable to noncontrolling interests	3	3	3
Comprehensive income attributable to BHE shareholders	$ 3,190	$ 2,106	$ 3,983

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

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Cash flows from operating activities	$ 1,780	$ 1,885	$ 2,450
Cash flows from investing activities:			
Investments in subsidiaries	(1,972)	(1,791)	(1,566)
Purchases of investments	(42)	(44)	(71)
Proceeds from sale of investments	42	45	68
Notes receivable from affiliate, net	(112)	(72)	(305)
Other, net	(5)	(22)	(8)
Net cash flows from investing activities	(2,089)	(1,884)	(1,882)
Cash flows from financing activities:			
Proceeds from BHE senior debt	—	3,166	—
Repayments of BHE senior debt	—	(1,045)	(1,379)
Repayments of BHE subordinated debt	—	—	(944)
Common stock purchases	(293)	(107)	(19)
Net proceeds from (repayments of) short-term debt	607	(2,348)	2,498
Tender offer premium paid	—	—	(406)
Other, net	(1)	(4)	(5)
Net cash flows from financing activities	313	(338)	(255)
Net change in cash and cash equivalents	4	(337)	313
Cash and cash equivalents at beginning of year	9	346	33
Cash and cash equivalents at end of year	$ 13	$ 9	$ 346

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

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
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 a marketable security with changes in fair value recognized in net income. As of December 31, 2019 and 2018, the fair value of BHE's investment in BYD common stock was $1,122 million and $1,435 million

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2019, 2018 and 2017 were $2.0 billion, $2.3 billion and $3.0 billion, respectively. In January 2020, BHE received cash dividends from its subsidiaries totaling $118 million.

Guarantees and commitments - BHE has issued guarantees and letters of credit in respect of subsidiary and equity method investments aggregating $277 million and commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $2.4 billion.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures regarding long-term obligations (Notes 9, 10 and 11) and shareholders' equity (Note 18).

Schedule II

BERKSHIRE HATHAWAY ENERGY COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2019
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Charged to Income	Column C Acquisition Reserves	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 2019	$ 42	$ 47	$ —	$ (45)	$ 44
Year ended 2018	40	43	—	(41)	42
Year ended 2017	33	42	—	(35)	40
Reserves Not Deducted From Assets(1):					
Year ended 2019	$ 13	$ 4	$ —	$ (5)	$ 12
Year ended 2018	13	6	—	(6)	13
Year ended 2017	13	7	—	(7)	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,	
	2019	**2018**
ASSETS		
Current assets:		
Receivables from affiliates	$ 2	$ 2
Total current assets	2	2
Investments in and advances to subsidiaries	8,346	8,002
Total assets	$ 8,348	$ 8,004
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 6	$ 6
Payable to affiliate	1	429
Long-term debt	240	240
Total liabilities	247	675
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	6,422	5,650
Total member's equity	8,101	7,329
Total liabilities and member's equity	$ 8,348	$ 8,004

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

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Other income and (expense):			
Interest expense	$ (16)	$ (16)	$ (22)
Other, net	—	—	(30)
Loss before income taxes	(16)	(16)	(52)
Income tax benefit	(5)	(5)	(22)
Equity in undistributed earnings of subsidiaries	792	680	604
Net income	$ 781	$ 669	$ 574

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

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Net cash flows from operating activities	$ (12)	$ 2	$ (15)
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	12	(2)	130
Net cash flows from financing activities	12	(2)	15
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, 2019 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. The Condensed Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2019, 2018 and 2017.

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 and income taxes. MHC paid $12 million and $130 million in 2019 and 2017, respectively, and received $2 million in 2018 on behalf of MidAmerican Funding. In 2019, MHC transferred to MidAmerican Funding $440 million of its receivable from MidAmerican Funding in the form of a dividend.

Distribution to Parent - In 2019, MidAmerican Funding recorded a noncash dividend of $8 million for the transfer to BHE of corporate aircraft owned by MHC.

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, 2019	As of December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ 1
Receivable from parent	1	429
Investments and nonregulated property, net	2	12
Goodwill	1,270	1,270
Investments in and advances to subsidiaries	7,260	6,465
Total assets	$ 8,534	$ 8,177
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Payables to affiliates	$ 186	$ 172
Accrued income taxes	2	—
Deferred income taxes	—	3
Total liabilities	188	175
Shareholder's equity:		
Paid-in capital	2,430	2,430
Retained earnings	5,916	5,572
Total shareholder's equity	8,346	8,002
Total liabilities and shareholder's equity	$ 8,534	$ 8,177

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

Schedule I

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Other income	$ 1	$ 1	$ 1
Other interest expense	5	4	—
(Loss) income before income taxes	(4)	(3)	1
Income tax benefit	(1)	(1)	—
Equity in undistributed earnings of subsidiaries	795	682	603
Net income	$ 792	$ 680	$ 604

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,		
	2019	**2018**	**2017**
Net cash flows from operating activities	$ (4)	$ 5	$ (1)
Net cash flows from investing activities:			
Capital expenditures	—	—	(2)
Net change in amounts receivable from parent	(12)	2	(130)
Net cash flows from investing activities	(12)	2	(132)
Net cash flows from financing activities:			
Net change in amounts payable to subsidiaries	1	2	(1)
Net change in note payable to Berkshire Hathaway Energy Company	15	(8)	133
Net cash flows from financing activities	16	(6)	132
Net change in cash and cash equivalents	—	1	(1)
Cash and cash equivalents at beginning of year	1	—	1
Cash and cash equivalents at end of year	$ 1	$ 1	$ —

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

Schedule I

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, 2019, 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. The Condensed Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2019, 2018 and 2017.

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 and income taxes. MHC paid $12 million and $130 million in 2019 and 2017, respectively, and received $2 million in 2018 on behalf of MidAmerican Funding.

Dividends Paid- In 2019, MHC recorded noncash dividends of $440 million for the transfer to MidAmerican Funding of MHC's receivable from MidAmerican Funding and $8 million for the transfer to BHE of corporate aircraft owned by MHC.

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, 2019
(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 2019	$ 7	$ 9	$ (11)	$ 5
Year ended 2018	$ 7	$ 8	$ (8)	$ 7
Year ended 2017	$ 7	$ 8	$ (8)	$ 7
Reserves Not Deducted From Assets[1]:				
Year ended 2019	$ 13	$ 4	$ (5)	$ 12
Year ended 2018	$ 13	$ 6	$ (6)	$ 13
Year ended 2017	$ 13	$ 7	$ (7)	$ 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.

Schedule II

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
MHC INC. AND SUBSIDIARIES
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2019
(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 2019	$ 7	$ 9	$ (11)	$ 5
Year ended 2018	$ 7	$ 8	$ (8)	$ 7
Year ended 2017	$ 7	$ 8	$ (8)	$ 7
Reserves Not Deducted From Assets [1]:				
Year ended 2019	$ 13	$ 4	$ (5)	$ 12
Year ended 2018	$ 13	$ 6	$ (6)	$ 13
Year ended 2017	$ 13	$ 7	$ (7)	$ 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, 2019 and 2018, 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, 2019, and the related notes and the schedules listed in the Index at Item 15(a)(2) (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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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 21, 2020

We have served as MHC's auditor since 1999.

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 288	$ 1
Trade receivables, net	291	363
Inventories	226	204
Other current assets	90	90
Total current assets	895	658
Property, plant and equipment, net	18,377	16,169
Goodwill	1,270	1,270
Regulatory assets	289	273
Investments and restricted investments	820	710
Receivable from affiliate	1	429
Other assets	188	121
Total assets	$ 21,840	$ 19,630

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, 2019	As of December 31, 2018
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 520	$ 575
Accrued interest	78	53
Accrued property, income and other taxes	226	300
Note payable to affiliate	171	156
Short-term debt	—	240
Current portion of long-term debt	—	500
Other current liabilities	220	122
Total current liabilities	1,215	1,946
Long-term debt	7,208	4,879
Regulatory liabilities	1,406	1,620
Deferred income taxes	2,621	2,319
Asset retirement obligations	704	552
Other long-term liabilities	340	312
Total liabilities	13,494	11,628
Commitments and contingencies (Note 13)		
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	5,916	5,572
Total shareholder's equity	8,346	8,002
Total liabilities and shareholder's equity	$ 21,840	$ 19,630

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,		
	2019	**2018**	**2017**
Operating revenue:			
Regulated electric	$ 2,237	$ 2,283	$ 2,108
Regulated natural gas and other	690	770	738
Total operating revenue	2,927	3,053	2,846
Operating expenses:			
Cost of fuel and energy	399	487	434
Cost of natural gas purchased for resale and other	412	469	447
Operations and maintenance	801	813	802
Depreciation and amortization	639	609	500
Property and other taxes	127	125	119
Total operating expenses	2,378	2,503	2,302
Operating income	549	550	544
Other income (expense):			
Interest expense	(286)	(231)	(215)
Allowance for borrowed funds	27	20	15
Allowance for equity funds	78	53	41
Other, net	52	31	39
Total other income (expense)	(129)	(127)	(120)
Income before income tax benefit	420	423	424
Income tax benefit	(372)	(257)	(180)
Net income	$ 792	$ 680	$ 604

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2016	$ —	$ 2,430	$ 4,288	$ 6,718
Net income	—	—	604	604
Balance, December 31, 2017	—	2,430	4,892	7,322
Net income	—	—	680	680
Balance, December 31, 2018	—	2,430	5,572	8,002
Net income	—	—	792	792
Dividends declared	—	—	(448)	(448)
Balance, December 31, 2019	$ —	$ 2,430	$ 5,916	$ 8,346

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, 2019	2018	2017
Cash flows from operating activities:			
Net income	$ 792	$ 680	$ 604
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	639	609	500
Amortization of utility plant to other operating expenses	33	34	34
Allowance for equity funds	(78)	(53)	(41)
Deferred income taxes and amortization of investment tax credits	152	32	334
Other, net	(7)	16	(13)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	56	(19)	(63)
Inventories	(22)	41	19
Derivative collateral, net	(1)	(1)	2
Contributions to pension and other postretirement benefit plans, net	(10)	(13)	(11)
Accrued property, income and other taxes, net	(74)	217	(42)
Accounts payable and other liabilities	7	(29)	72
Net cash flows from operating activities	1,487	1,514	1,395
Net cash flows from investing activities:			
Capital expenditures	(2,810)	(2,332)	(1,773)
Purchases of marketable securities	(156)	(263)	(143)
Proceeds from sales of marketable securities	138	223	137
Proceeds from sales of other investments	1	17	2
Other investment proceeds	13	15	1
Net change in amounts receivable from parent	(12)	2	(130)
Other, net	13	30	(3)
Net cash flows from investing activities	(2,813)	(2,308)	(1,909)
Net cash flows from financing activities:			
Proceeds from long-term debt	2,326	687	990
Repayments of long-term debt	(500)	(350)	(255)
Net change in amounts receivable from/payable to affiliates	15	(8)	133
Net (repayments of) proceeds from short-term debt	(240)	240	(99)
Other, net	(1)	—	—
Net cash flows from financing activities	1,600	569	769
Net change in cash and cash equivalents and restricted cash and cash equivalents	274	(225)	255
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	57	282	27
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 331	$ 57	$ 282

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

MHC INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

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, and its direct wholly owned nonregulated subsidiary is Midwest Capital Group, Inc.

(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 21, 2020, which is the date the Consolidated Financial Statements were issued. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2019, 2018 and 2017.

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 2019, 2018 and 2017, MHC did not record any goodwill impairments.

(3) Property, Plant and Equipment, Net

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's property, plant and equipment, net, MHC had gross nonregulated property of $3 million and $24 million as of December 31, 2019 and 2018, respectively, and related accumulated depreciation and amortization of $1 million and $12 million as of December 31, 2019 and 2018, respectively, which, as of December 31, 2018, consisted primarily of a corporate aircraft owned by MHC. In 2019, MHC transferred the aircraft by dividend to MidAmerican Funding, which transferred it to BHE.

(4) Jointly Owned Utility Facilities

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(5) Regulatory Matters

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(6) Investments and Restricted Investments

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted 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, 2019 and 2018.

(7) Short-Term Debt and Credit Facilities

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 credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2019 and has a variable interest rate based on the Eurodollar rate plus a spread. As of December 31, 2019 and 2018, there were no borrowings outstanding under this credit facility. As of December 31, 2019, MHC was in compliance with the covenants of its credit facility.

(8) Long-Term Debt

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(9) Income Taxes

MHC's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2019	2018	2017
Current:			
Federal	$ (477)	$ (277)	$ (489)
State	(47)	(12)	(25)
	(524)	(289)	(514)
Deferred:			
Federal	164	42	338
State	(11)	(9)	(3)
	153	33	335
Investment tax credits	(1)	(1)	(1)
Total	$ (372)	$ (257)	$ (180)

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:

	2019	2018	2017
Federal statutory income tax rate	21 %	21 %	35 %
Income tax credits	(90)	(73)	(68)
State income tax, net of federal income tax benefit	(11)	(4)	(4)
Effects of ratemaking	(8)	(5)	(7)
Other, net	(1)	—	1
Effective income tax rate	(89)%	(61)%	(43)%

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

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

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 368	$ 405
Asset retirement obligations	234	164
Employee benefits	26	47
Other	76	85
Total deferred income tax assets	704	701
Deferred income tax liabilities:		
Depreciable property	(3,253)	(2,947)
Regulatory assets	(68)	(62)
Other	(4)	(11)
Total deferred income tax liabilities	(3,325)	(3,020)
Net deferred income tax liability	$ (2,621)	$ (2,319)

As of December 31, 2019, MHC has available $51 million of state tax carryforwards, principally related to $745 million of net operating losses, that expire at various intervals between 2020 and 2038.

The United States Internal Revenue Service has closed its examination of MHC's income tax returns through December 31, 2011. The statute of limitations for MHC's state income tax returns have expired through December 31, 2009, with the exception of Iowa and Illinois, for which the statute of limitations have expired through December 31, 2015, except for the impact of any federal audit adjustments. 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 statute of limitations is not closed.

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):

	2019	2018
Beginning balance	$ 10	$ 12
Additions based on tax positions related to the current year	5	4
Additions for tax positions of prior years	10	47
Reductions based on tax positions related to the current year	(5)	(4)
Reductions for tax positions of prior years	(12)	(48)
Interest and penalties	—	(1)
Ending balance	$ 8	$ 10

As of December 31, 2019, MHC had unrecognized tax benefits totaling $27 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MHC's effective income tax rate.

(10) Employee Benefit Plans

Refer to Note 10 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MHC's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MHC to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2019	2018	2017
Pension costs	$ 4	$ 3	$ 4
Other postretirement costs	(2)	(2)	(3)

(11) Asset Retirement Obligations

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(12) Fair Value Measurements

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(13) Commitments and Contingencies

Refer to Note 13 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.

(14) Revenue from Contracts with Customers

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements. Additionally, MHC had $2 million and $4 million of other revenue from contracts with customers for the year ended December 31, 2019 and 2018, respectively.

(15) Other Income (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):

	2019	2018	2017
Non-service cost components of postretirement employee benefit plans	$ 17	$ 21	$ 18
Corporate-owned life insurance income	24	6	13
Interest income and other, net	11	4	8
Total	$ 52	$ 31	$ 39

(16) Supplemental Cash Flow Information

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 cash and cash equivalents as of December 31, 2019 and 2018, consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2019 and 2018 as presented in the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2019	**2018**
Cash and cash equivalents	$ 288	$ 1
Restricted cash and cash equivalents in other current assets	43	56
Total cash and cash equivalents and restricted cash and cash equivalents	$ 331	$ 57

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

	2019	**2018**	**2017**
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 228	$ 201	$ 193
Income taxes received, net	$ 451	$ 494	$ 463
Supplemental disclosure of non-cash investing and financing transactions:			
Accounts payable related to utility plant additions	$ 337	$ 371	$ 224
Dividend of receivable from parent and corporate aircraft	$ 448	$ —	$ —

(17) 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 $41 million, $44 million and $46 million for 2019, 2018 and 2017, respectively. Additionally, in 2018, MHC received $15 million from BHE for the transfer of corporate aircraft owned by MidAmerican Energy.

MHC reimbursed BHE in the amount of $14 million, $11 million and $7 million in 2019, 2018 and 2017, 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 $139 million, $127 million and $122 million in 2019, 2018 and 2017, 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 $171 million at an interest rate of 1.944% as of December 31, 2019, and $156 million at an interest rate of 2.629% as of December 31, 2018, 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 2019 and 2018.

MHC pays all obligations of and receives all payments to MidAmerican Funding, including primarily interest costs on MidAmerican Funding's long-term debt and income taxes. Additionally, in 2017, MHC paid for MidAmerican Funding's redemption of a portion of its long-term debt through a tender offer. On behalf of MidAmerican Funding, MHC paid net amounts of $12 million and $130 million in 2019 and 2017, respectively and received a net amount of $2 million for 2018.

MHC had accounts receivable from affiliates of $7 million and $433 million as of December 31, 2019 and 2018, respectively, that are reflected in receivables, net and receivable from affiliate on the Consolidated Balance Sheets. MHC also had accounts payable to affiliates of $11 million and $12 million as of December 31, 2019 and 2018, respectively, that are included in accounts payable on the Consolidated Balance Sheets. In 2019, MHC recorded noncash dividends of $440 million for the transfer to MidAmerican Funding of MHC's receivable from MidAmerican Funding and $8 million for the transfer to BHE of corporate aircraft owned by MHC.

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 payable to BHE of $83 million and $156 million as of December 31, 2019 and 2018, respectively. MHC received net cash receipts for federal and state income taxes from BHE totaling $451 million, $494 million and $463 million for the years ended December 31, 2019, 2018 and 2017, 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 $23 million and $20 million as of December 31, 2019 and 2018, respectively, and similar amounts payable to affiliates totaled $47 million and $36 million, as of December 31, 2019 and 2018, respectively. See Note 10 for further information pertaining to pension and postretirement accounting.

(18) Segment Information

MHC 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 gas owned by others through its distribution system. Pricing for regulated electric and regulated natural 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 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2019	2018	2017
Operating revenue:			
Regulated electric	$ 2,237	$ 2,283	$ 2,108
Regulated natural gas	660	754	719
Other	30	16	19
Total operating revenue	$ 2,927	$ 3,053	$ 2,846
Depreciation and amortization:			
Regulated electric	$ 593	$ 565	$ 458
Regulated natural gas	46	44	42
Total depreciation and amortization	$ 639	$ 609	$ 500
Operating income:			
Regulated electric	$ 473	$ 469	$ 472
Regulated natural gas	71	81	72
Other	5	—	—
Total operating income	$ 549	$ 550	$ 544
Interest expense:			
Regulated electric	$ 259	$ 208	$ 196
Regulated natural gas	22	19	18
Other	5	4	1
Total interest expense	$ 286	$ 231	$ 215
Income tax (benefit) expense:			
Regulated electric	$ (384)	$ (273)	$ (212)
Regulated natural gas	12	16	29
Other	—	—	3
Total income tax (benefit) expense	$ (372)	$ (257)	$ (180)
Net income:			
Regulated electric	$ 739	$ 628	$ 570
Regulated natural gas	52	54	35
Other	1	(2)	(1)
Net income	$ 792	$ 680	$ 604
Capital expenditures:			
Regulated electric	$ 2,684	$ 2,223	$ 1,686
Regulated natural gas	126	109	87
Total capital expenditures	$ 2,810	$ 2,332	$ 1,773

	As of December 31,		
	2019	2018	2017
Total assets:			
Regulated electric	$ 20,284	$ 17,702	$ 16,105
Regulated natural gas	1,547	1,485	1,482
Other	9	443	451
Total assets	$ 21,840	$ 19,630	$ 18,038

Goodwill by reportable segment as of December 31, 2019 and 2018 was as follows (in millions):

Regulated electric	$ 1,191
Regulated natural gas	79
Total	$ 1,270

EXHIBIT INDEX

Exhibit No.	Description
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 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).
4.4	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).
4.5	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).
4.6	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).
4.7	Ninth Supplemental Indenture, dated as of November 8, 2013, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 3.750% Senior Notes due 2023 and the 5.150% Senior Notes due 2043 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 8, 2013).
4.8	Tenth Supplemental Indenture, dated as December 4, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 2.40% Senior Notes due 2020, the 3.50% Senior Notes due 2025 and the 4.50% Senior Notes due 2045 (incorporated by reference to Exhibit 4.8 to the Berkshire Hathaway Energy Company Registration Statement No. 333-200928 dated December 12, 2014).
4.9	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 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).

Exhibit No.	Description
4.10	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 2.80% Senior Notes due 2023, the 3.25% Senior Notes due 2028 and the 3.80% 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).
4.11	Thirteenth Supplemental Indenture, dated as of July 25, 2018, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.45% Senior Notes due 2049 (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, 2018).
4.12	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated October 23, 1997).
4.13	Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes due 2028 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated September 17, 1998).
4.14	Indenture, dated May 1, 2000, between NV Energy, Inc. (under its former name, Sierra Pacific Resources) and The Bank of New York, relating to the issuance of debt securities (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Current Report on Form 8-K dated May 22, 2000).
4.15	Form of Officers' Certificate establishing the terms of NV Energy, Inc.'s 6.25% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Current Report on Form 8-K dated November 19, 2010).
4.16	Trust Deed, dated December 15, 1997 among CE Electric UK Funding Company, AMBAC Insurance UK Limited and The Law Debenture Trust Corporation, p.l.c., Trustee (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.17	Insurance and Indemnity Agreement, dated December 15, 1997 by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.18	Supplemental Agreement to Insurance and Indemnity Agreement, dated September 19, 2001, by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.19	Trust 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).
4.20	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).
4.21	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).
4.22	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).

Exhibit No.	Description
4.23	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).
4.24	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).
4.25	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).
4.26	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).
4.27	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).
4.28	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).
4.29	£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).
4.30	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).
4.31	£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).
4.32	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.33	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).
4.34	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).
4.35	£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).
4.36	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).

Exhibit No.	Description
4.37	£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).
4.38	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).
4.39	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).
4.40	Trust Deed, dated as of May 24, 2019, among Northern Electric Finance plc, Northern Powergrid (Northeast) Limited, and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.75% Guaranteed Bonds due 2049 (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, 2019).
4.41	Trust Deed, dated as of October 9, 2019, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £300,000,000 in principal amount of the 2.25% Guaranteed Bonds due 2059 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).
4.42	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).
4.43	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).
4.44	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).
4.45	Fiscal Agency Agreement, dated as of July 12, 2018, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $450,000,000 in principal amount of the 4.30% Senior Bonds due 2049 (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, 2018).
4.46	Amendment No. 1 to the Fiscal Agency Agreement, dated as of July 17, 2018, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to an additional $200,000,000 in principal amount of the 4.30% Senior Bonds due 2049 (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, 2019).
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).
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).

Exhibit No.	Description
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.106 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.60	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).
4.61	Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to C$350,000,000 in principal amount of the 4.09% Series 2015-1 Medium-Term Notes due 2045 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2015).

Exhibit No.	Description
4.62	Twenty-First Supplemental Indenture, dated December 14, 2018, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.64 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2018).
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	$3,500,000,000 Amended and Restated Credit Agreement, dated as of May 31, 2019, 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, 2019).
10.2	Amended and Restated £150,000,000 Facility Agreement, dated as of October 18, 2019, among Northern Powergrid Holdings Company, as Guarantor, Northern Powergrid (Yorkshire) plc and Northern Powergrid (Northeast) Limited, as Borrowers, and Santander UK plc, Lloyds Bank plc and National Westminster Bank 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 September 30, 2019).
10.3	Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders.
10.4	Fifth Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.5	Fourth Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink, L.P., as borrower, AltaLink Management, Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.6	Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.7	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2014 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
14.1	Berkshire Hathaway Energy Company Code of Ethics For Chief Executive Officer, Chief Financial Officer and Other Covered Officers (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.

Exhibit No.	Description
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).
10.8*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.9*	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).
10.10*	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).
10.11*	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).
10.12*	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).
10.13*	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).
10.14*	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).
10.15*	PacifiCorp Long Term Incentive Partnership Plan effective January 1, 2014 and Restated Effective December 1, 2019.
14.2	Code of Ethics (incorporated by reference to Exhibit 14.1 to the PacifiCorp Transition Report on Form 10-K for the nine-month period ended December 31, 2006).
23.2	Consent of Deloitte & Touche LLP.
31.3	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.3	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.4	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.67 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 29 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)a	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
4.1	8-K	July 13, 2018
4.1	8-K	March 1, 2019

10.16 $600,000,000 Amended and Restated Credit Agreement, dated as of May 31, 2019, 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, 2019).

10.17 $600,000,000 Amended and Restated Credit Agreement, dated as of May 31, 2019, 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 10.3 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).

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	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).
4.74	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).
4.75	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).
4.76	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).
4.77	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).
4.78	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).
4.79	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).
4.80	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).
4.81	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).
4.82	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).
4.83	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).
4.84	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).
4.85	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).
4.86	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).
4.87	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).

Exhibit No.	Description
4.88	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).
4.89	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 (incorporated by reference to Exhibit 4.91 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2017).
4.90	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).
4.91	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).
4.92	Eighth Supplemental Indenture, dated January 9, 2019, 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 January 9, 2019).
4.93	Specimen of 3.65% First Mortgage Bonds due 2029 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).
4.94	Specimen of 4.25% First Mortgage Bonds due 2049 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).
4.95	Amendment No. 1 to the Eighth Supplemental Indenture, dated as of October 15, 2019, 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 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).
4.96	Ninth Supplemental Indenture, dated as of October 15, 2019, 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 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).
4.97	Specimen of 3.15% First Mortgage Bond due 2050 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).
4.98	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).
4.99	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).
4.100	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).
4.101	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).
4.102	$900,000,000 Amended and Restated Credit Agreement, dated as of May 31, 2019, 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 10.4 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).

Exhibit No.	Description
4.103	$400,000,000 Credit Agreement, dated as of August 30, 2019, among MidAmerican Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, and Mizuho Bank, LTD., as Administrative Agent (incorporated by reference to Exhibit 10.6 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

4.104	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 as amended December 21, 2017 (incorporated by reference to Exhibit 3.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
4.105	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).
4.106	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).
10.18	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).
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

4.107	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).
4.108	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).

Exhibit No.	Description
4.109	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).
4.110	Officer's Certificate establishing the terms of Nevada Power Company's 6.65% 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).
4.111	Officer's Certificate establishing the terms of Nevada Power Company's 6.75% 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).
4.112	Officer's Certificate establishing the terms of Nevada Power Company 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (incorporated by reference to Exhibit 4.1 to Nevada Power Company Current Report on Form 8-K dated September 10, 2010).
4.113	Officer's Certificate establishing the terms of Nevada Power Company 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).
4.114	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).
4.115	Officer's Certificate establishing the terms of Nevada Power Company's 2.75% General and Refunding Mortgage Notes, Series BB, due 2020 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated April 12, 2018).
4.116	Officer's Certificate establishing the terms of Nevada Power Company's 3.70% General and Refunding Mortgage Notes, Series CC, due 2029 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2019).
4.117	Officer's Certificate establishing the terms of Nevada Power Company's 2.40% General and Refunding Mortgage Notes, Series DD, due 2030 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2020).
4.118	Officer's Certificate establishing the terms of Nevada Power Company's 3.125% General and Refunding Mortgage Notes, Series EE, due 2050 (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2020).
10.19	$400,000,000 Third Amended and Restated Credit Agreement, dated as of May 31, 2019, among Nevada Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.5 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).

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	Amended and Restated By-Laws of Sierra Pacific Power Company as amended December 21, 2017 (incorporated by reference to Exhibit 3.2 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
4.119	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).

Exhibit No.	Description
4.120	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).
4.121	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).
10.20	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).
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.

BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC

4.122	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).
4.123	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).
4.124	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.75% 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).
4.125	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).
4.126	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).
4.127	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).
10.21	$250,000,000 Third Amended and Restated Credit Agreement, dated as of May 31, 2019, among Sierra Pacific Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.6 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).

Exhibit No.	**Description**
ALL REGISTRANTS	
101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2019 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 21st day of February 2020.

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 21, 2020
/s/ Patrick J. Goodman* Patrick J. Goodman	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2020
/s/ Gregory E. Abel* Gregory E. Abel	Chairman of the Board of Directors	February 21, 2020
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 21, 2020
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 21, 2020
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	February 21, 2020
*By: /s/ Natalie L. Hocken Natalie L. Hocken	Attorney-in-Fact	February 21, 2020

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 21st day of February 2020.

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 and Chief Executive Officer (principal executive officer)	February 21, 2020
/s/ Nikki L. Kobliha Nikki L. Kobliha	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 21, 2020
/s/ Stefan A. Bird Stefan A. Bird	Director	February 21, 2020
/s/ Patrick J. Goodman Patrick J. Goodman	Director	February 21, 2020
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 21, 2020
/s/ Gary W. Hoogeveen Gary W. Hoogeveen	Director	February 21, 2020

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 21st day of February 2020.

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 21, 2020
/s/ Thomas B. Specketer Thomas B. Specketer	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2020
/s/ Robert B. Berntsen Robert B. Berntsen	Director	February 21, 2020

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 21st day of February 2020.

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 21, 2020
/s/ Thomas B. Specketer Thomas B. Specketer	Vice President and Controller (principal financial and accounting officer)	February 21, 2020
/s/ Daniel S. Fick Daniel S. Fick	Manager	February 21, 2020
/s/ Patrick J. Goodman Patrick J. Goodman	Manager	February 21, 2020
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 21, 2020

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 21st day of February 2020.

NEVADA POWER COMPANY

/s/ Douglas A. Cannon

Douglas A. Cannon
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/ Douglas A. Cannon Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 21, 2020
/s/ Michael E. Cole Michael E. Cole	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2020
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 21, 2020
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 21, 2020
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 21, 2020
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 21, 2020

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 21st day of February 2020.

SIERRA PACIFIC POWER COMPANY

/s/ Douglas A. Cannon
Douglas A. Cannon
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/ Douglas A. Cannon Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 21, 2020
/s/ Michael E. Cole Michael E. Cole	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2020
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 21, 2020
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 21, 2020
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 21, 2020
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 21, 2020

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 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	Delaware
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
BHE Wind, LLC	Delaware
HomeServices of America, Inc.	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-228511 on Form S-8 of our report dated February 21, 2020, 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, 2019.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2020

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-227592 on Form S-3 of our report dated February 21, 2020, 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, 2019.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 21, 2020

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-225916 on Form S-3 of our report dated February 21, 2020, relating to the financial statements and financial statement schedule of MidAmerican Energy Company, appearing in this Annual Report on Form 10-K of MidAmerican Energy Company for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2020

EXHIBIT 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-234207 on Form S-3 of our report dated February 21, 2020 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, 2019.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 21, 2020

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 Jeffery B. Erb 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, 2019 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 21, 2020

/s/ William J. Fehrman	/s/ Patrick J. Goodman
WILLIAM J. FEHRMAN	PATRICK J. GOODMAN
/s/ Gregory E. Abel	/s/ Warren E. Buffett
GREGORY E. ABEL	WARREN E. BUFFETT
/s/ Marc D. Hamburg	/s/ Walter Scott, Jr.
MARC D. HAMBURG	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 21, 2020

/s/ William J. Fehrman
William J. Fehrman
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 21, 2020

/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 21, 2020

/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 21, 2020

/s/ Nikki L. Kobliha
Nikki L. Kobliha
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 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 21, 2020

/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 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 21, 2020

/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 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 21, 2020

/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 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 21, 2020

/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, Douglas A. Cannon, 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 21, 2020

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.10

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

I, Michael E. Cole, 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 21, 2020

/s/ Michael E. Cole
Michael E. Cole
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, Douglas A. Cannon, 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 21, 2020

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.12

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

I, Michael E. Cole, 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 21, 2020

/s/ Michael E. Cole
Michael E. Cole
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, 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, 2019 (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 21, 2020

/s/ William J. Fehrman
William J. Fehrman
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, 2019 (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 21, 2020

/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 PacifiCorp for the annual period ended December 31, 2019 (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 PacifiCorp.

Date: February 21, 2020

/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, 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 PacifiCorp for the annual period ended December 31, 2019 (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 PacifiCorp.

Date: February 21, 2020

/s/ Nikki L. Kobliha
Nikki L. Kobliha
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 , 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 MidAmerican Energy Company for the annual period ended December 31, 2019 (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 MidAmerican Energy Company.

Date: February 21, 2020

/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, 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 MidAmerican Energy Company for the annual period ended December 31, 2019 (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 MidAmerican Energy Company.

Date: February 21, 2020

/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, 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 MidAmerican Funding, LLC for the annual period ended December 31, 2019 (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 MidAmerican Funding, LLC.

Date: February 21, 2020

/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, 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 MidAmerican Funding, LLC for the annual period ended December 31, 2019 (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 MidAmerican Funding, LLC.

Date: February 21, 2020

/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, Douglas A. Cannon, President and 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, 2019 (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 21, 2020

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.10

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

I, Michael E. Cole, Vice President and 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, 2019 (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 21, 2020

/s/ Michael E. Cole
Michael E. Cole
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, Douglas A. Cannon, President and 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, 2019 (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 21, 2020

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.12

CERTIFICATION PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Michael E. Cole, Vice President and 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, 2019 (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 21, 2020

/s/ Michael E. Cole
Michael E. Cole
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, 2019 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, 2019. There were no mining-related fatalities during the year ended December 31, 2019. 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, 2019.

	Mine Safety Act						Legal Actions		
Mining Facilities	Section 104 Significant and Substantial Citations[(1)]	Section 104(b) Orders[(2)]	Section 104(d) Citations/ Orders[(3)]	Section 110(b)(2) Violations[(4)]	Section 107(a) Imminent Danger Orders[(5)]	Total Value of Proposed MSHA Assessments (in thousands)	Pending as of Last Day of Period[(6)]	Instituted During Period	Resolved During Period
Bridger (surface)	—	—	—	—	—	—	—	—	—
Bridger (underground)	5	—	2	—	—	$ 43	1	3	4
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. Subsequently, MSHA modified the Section 104(d)(1) citation to a Section 104(a) citation and also vacated the Section 104(d)(1) order.

(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.

(6) Amounts include one contest 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.