BLACK HILLS CORP /SD/
Form 10-K
February 26, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
o 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 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	7001 Mount Rushmore Road Rapid City, South Dakota 57702	IRS Identification Number 46-0458824

Registrant's telephone number, including area code
(605) 721-1700
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

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

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes x No o

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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.

Large accelerated filer	x	Accelerated filer	o
Non-accelerated filer	o	(Do not check if a smaller reporting company)	
		Smaller reporting company	o
		Emerging growth company	o

If an emerging growth company, indicate by check mark if the Registrant has 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. o

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

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2017 $3,563,087,139

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2018
Common stock, $1.00 par value	53,544,761 shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2018 Annual Meeting of Stockholders to be held on April 24, 2018, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction
AltaGas	AltaGas Renewable Energy Colorado LLC, a subsidiary of AltaGas Ltd.
AOCI	Accumulated Other Comprehensive Income
APSC	Arkansas Public Service Commission
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
BHC	Black Hills Corporation; the Company
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, includes Black Hills Gas Resources, Inc. and Black Hills Plateau Production LLC, direct wholly-owned subsidiaries of Black Hills Exploration and Production, Inc.
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Gas	Black Hills Gas, LLC, a subsidiary of Black Hills Gas Holdings, which was previously named SourceGas LLC.
Black Hills Gas Holdings	Black Hills Gas Holdings, LLC, a subsidiary of Black Hills Utility Holdings, which was previously named SourceGas Holdings LLC
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Arkansas Gas	Includes the acquired SourceGas utility Black Hills Energy Arkansas, Inc. utility operations
Black Hills Energy Colorado Electric	Includes Colorado Electric’s utility operations
Black Hills Energy Colorado Gas	Includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Colorado gas operations and RMNG
Black Hills Energy Iowa Gas	Includes Black Hills Energy Iowa gas utility operations
Black Hills Energy Kansas Gas	Includes Black Hills Energy Kansas gas utility operations
Black Hills Energy Nebraska Gas	Includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Nebraska gas operations
Black Hills Energy Services	A Choice Gas supplier acquired in the SourceGas Acquisition
Black Hills Energy South Dakota Electric	Includes Black Hills Power’s operations in South Dakota, Wyoming and Montana
Black Hills Energy Wyoming Electric	Includes Cheyenne Light’s electric utility operations

Black Hills Energy Wyoming Gas	Includes Cheyenne Light’s natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution’s Wyoming gas operations
Black Hills Gas Distribution	Black Hills Gas Distribution, LLC, a company acquired in the SourceGas Acquisition that conducts the gas distribution operations in Colorado, Nebraska and Wyoming. It was formerly named SourceGas Distribution LLC.
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
BHSC	Black Hills Service Company LLC, a direct, wholly-owned subsidiary of Black Hills Corporation

Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Busch Ranch	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and AltaGas. Colorado Electric has a 50% ownership interest in the wind farm.
Ceiling Test	Related to our Oil and Gas subsidiary, capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties.
CAPP	Customer Appliance Protection Plan - acquired in the SourceGas Acquisition
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural-gas fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Services is one of the Choice Gas suppliers.
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Interstate Gas (CIG)	Colorado Interstate Natural Gas Pricing Index
Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement.
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
CPP	Clean Power Plan
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
CVA	Credit Valuation Adjustment

DART	Days Away Restricted Transferred (number of cases with days away from work or job transfer or restrictions multiplied by 200,000 then divided by total hours worked for all employees during the year covered)
DC	Direct current
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan

Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Electricity purchased by one utility from another utility to take the place of electricity that would have cost more to produce on the utility's own system
EIA	Environmental Improvement Adjustment
Energy West	Energy West Wyoming, Inc., a subsidiary of Gas Natural, Inc. Energy West is an acquisition we closed on July 1, 2015.
Enserco	Enserco Energy Inc., a former wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations in this Annual Report filed on Form 10-K
EPA	United States Environmental Protection Agency
Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028.
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FDIC	Federal Depository Insurance Corporation
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GADS	Generation Availability Data System
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
IEEE	Institute of Electrical and Electronics Engineers
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Loveland Area Project	Part of the Western Area Power Association transmission system
MAPP	Mid-Continent Area Power Pool
MATS	

	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day

Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MGP	Manufactured Gas Plant
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
NERC	North American Electric Reliability Corporation
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service.
NO_x	Nitrogen oxide
NOL	Net operating loss
NPSC	Nebraska Public Service Commission
NWPL	Northwest Interstate Natural Gas Pricing Index
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	Occupational Safety & Health Administration
OSM	U.S. Department of the Interior's Office of Surface Mining
PCA	Power Cost Adjustment
PCCA	Power Capacity Cost Adjustment
Peak View	$109 million 60 MW wind generating project owned by Colorado Electric, placed in service on November 7, 2016 and adjacent to Busch Ranch Wind Farm
PPA	Power Purchase Agreement
PUHCA 2005	Public Utility Holding Company Act of 2005
REPA	Renewable Energy Purchase Agreement
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2021
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas Distribution in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SAIDI	System Average Interruption Duration Index
SDPUC	South Dakota Public Utilities Commission

SEC	U. S. Securities and Exchange Commission
Service Guard	Home appliance repair product offering for both natural gas and electric
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide

S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings
SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming, and Montana
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
TCIR	Total Case Incident Rate (average number of work-related injuries incurred by 100 workers during a one-year period)
Tech Services	Non-regulated product lines within Black Hills Corporation that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owner gas infrastructure facilities, typically through one-time contracts.
TFA	Transmission Facility Adjustment
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
Winter Storm Atlas	An October 2013 blizzard that impacted South Dakota Electric. It was the second most severe blizzard in Rapid City's history.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by PacifiCorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.
Wyoming Electric	Includes Cheyenne Light's electric utility operations
Wyoming Gas	Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management's Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a customer-focused, growth-oriented, vertically-integrated utility company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, with the purchase of the Wyodak Coal Mine, we began producing and selling energy through non-regulated businesses.

We operate our business in the United States, reporting our operating results through our regulated Electric Utilities, regulated Gas Utilities, Power Generation and Mining segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 210,000 electric customers in South Dakota, Wyoming, Colorado and Montana. Our Electric Utilities own 941 MW of generation and 8,839 miles of electric transmission and distribution lines. For additional information, see the Key Elements of our Business Strategy in Item 7.

Our Gas Utilities segment serves approximately 1,042,000 natural gas utility customers in Arkansas, Colorado, Iowa, Nebraska, Kansas and Wyoming. Our Gas Utilities own and operate 4,656 miles of intrastate gas transmission pipelines and 40,455 miles of gas distribution mains and service lines, seven natural gas storage sites, over 45,000 horsepower of compression and nearly 600 miles of gathering lines. On February 12, 2016, we acquired SourceGas Holdings, LLC, adding four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming. For additional information on this acquisition, see the Key Elements of our Business Strategy in Item 7 and Note 2 in the Notes to Consolidated Financial Statements in Item 8.

Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells the coal primarily under long-term contracts to mine-mouth electric generation facilities including our own regulated and non-regulated generating plants. For additional information, see the Key Elements of our Business Strategy in Item 7.

Our segments generated the following income from continuing operations available for common stock for the year ended December 31, 2017 and had the following total assets at December 31, 2017 (excluding Corporate and Other):

	Income (loss) from continuing operations available for common stock for the year ended December 31, 2017 (in thousands)	Total Assets as of December 31, 2017
Electric Utilities	$110,082	$2,906,275
Gas Utilities	$65,795	$3,426,466
Power Generation	$46,479	$60,852
Mining	$14,386	$65,455

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90 percent of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets with minimal value left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018. The results of our Oil and Gas segment are reflected in discontinued operations, other than certain general and administrative and interest costs. BHEP's assets and liabilities are classified as held for sale. See Note 21 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Segment Financial Information

We discuss our business strategy and other prospective information in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations. Financial information regarding our business segments is incorporated herein by reference to Item 8 - Financial Statements and Supplementary Data, and particularly Note 5 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Electric Utilities Segment

We conduct electric utility operations through our South Dakota, Wyoming and Colorado subsidiaries. Our Electric Utilities generate, transmit and distribute electricity to approximately 210,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services through our Tech Services product lines.

Capacity and Demand. System peak demands for the Electric Utilities for each of the last three years are listed below:

System Peak Demand (in MW)					
2017		2016		2015	
Summer	Winter	Summer	Winter	Summer	Winter

South Dakota Electric	447	402	438	389	424	369
Wyoming Electric [(a)]	249	230	236	230	212	202
Colorado Electric [(b)]	398	299	412	302	392	303
Total Electric Utilities' Peak Demands	1,094	931	1,086	921	1,028	874

(a) The July 2017 summer peak load of 249 surpassed previous summer peak record load of 236 set in July 2016. The winter peak record of 230 was set in December 2016.

(b) The July 2016 summer peak load of 412 surpassed previous summer peak record load of 406 set in June 2016.

Regulated Power Plants. As of December 31, 2017, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
South Dakota Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	58%	55.0	2014
Wygen III [(b)]	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak [(c)]	Coal	Gillette, Wyoming	20%	72.4	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	80.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT [(a)]	Gas	Cheyenne, Wyoming	100%	37.0	2014
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Colorado Electric:					
Busch Ranch Wind Farm [(d)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View Wind Farm [(e)]	Wind	Pueblo, Colorado	100%	60.0	2016
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
Pueblo Airport Generation CT [(f)]	Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1-5	Oil	Pueblo, Colorado	100%	10.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
Total MW Capacity				941.1	

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(a) Cheyenne Prairie, a 132 MW natural gas-fired power generation facility, was placed into commercial operation on October 1, 2014, to support the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 95 MW unit that is jointly-owned by Wyoming Electric (40 MW) and South Dakota Electric (55 MW).

(b) Wygen III, a 110 MW mine-mouth coal-fired power plant, is operated by South Dakota Electric. South Dakota Electric has a 52% ownership interest, MDU owns 25% and the City of Gillette owns the remaining 23% interest. Our WRDC coal mine supplies all of the fuel for the plant.

(c) Wyodak, a 362 MW mine-mouth coal-fired power plant, is owned 80% by PacifiCorp and 20% by South Dakota Electric. This baseload plant is operated by PacifiCorp and our WRDC coal mine supplies all of the fuel for the plant.

(d) Busch Ranch Wind Farm, a 29 MW wind farm, is operated by Colorado Electric. Colorado Electric has a 50% ownership interest in the wind farm and AltaGas owns the remaining 50%. Colorado Electric has a 25-year REPA with AltaGas for their 14.5 MW of power from the wind farm.

(e) Peak View Wind Farm achieved commercial operation on November 7, 2016.

(f) Colorado Electric's 40 MW combustion turbine achieved commercial operation on December 29, 2016.

The Electric Utilities' annual average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 is as follows:

Fuel Source (dollars per MWh)	2017	2016	2015
Coal	$10.95	$11.27	$10.89
Natural Gas	$34.05	$30.59	$51.14
Diesel Oil [(a)]	$210.11	$149.13	$303.16
Total Average Fuel Cost	$12.80	$12.99	$14.62
Purchased Power - Coal, Gas and Oil	$45.63	$48.36	$47.81
Purchased Power - Renewable Sources	$53.08	$51.95	$50.92

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(a) Included in the Price per MWh for Diesel Oil are unit start-up costs. The diesel-fueled generating units are generally used as supplemental peaking units and the cost per MWh is reflective of how often the units are started and how long the units are run.

Our Electric Utilities' power supply, by resource as a percent of the total power supply for our energy needs for the years ended December 31 is as follows:

Power Supply	2017	2016	2015
Coal	32 %	33 %	33 %
Gas, Oil and Wind	8	7	4
Total Generated	40	40	37
Purchased [(a)]	60	60	63
Total	100%	100%	100%

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(a) Wind represents approximately 6%, 7% and 5% of our purchased power in 2017, 2016, and 2015, respectively.

Purchased Power. We have executed various agreements to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation. Key contracts include:

- South Dakota Electric's PPA with PacifiCorp expiring on December 31, 2023, which provides for the purchase of 50 MW of coal-fired baseload power;

- Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, which provides 200 MW of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is reported and accounted for as a capital lease within our business segments and is eliminated on the accompanying Consolidated Financial Statements;

- Colorado Electric's PPA with AltaGas expiring on October 16, 2037, which provides up to 14.5 MW of wind energy from AltaGas' owned interest in the Busch Ranch Wind Farm;

- Wyoming Electric's PPA with Black Hills Wyoming expiring on December 31, 2022, whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019, subject to WPSC and FERC approval in order to obtain regulatory treatment. The purchase price related to the option is $2.6 million per MW (65 MWs), adjusted for all depreciated capital additions since 2009, and reduced by depreciation (approximately $5 million per year) over a 35-year life beginning January 1, 2009. The net book value of

Wygen I at December 31, 2017 was $69 million and if Wyoming Electric had exercised the purchase option at year-end 2017, the estimated purchase price would have been approximately $133 million;

- Wyoming Electric's 20-year PPA with Duke Energy expiring on September 3, 2028, which provides up to 29.4 MW of wind energy from the Happy Jack Wind Farm to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility's output to South Dakota Electric;

- Wyoming Electric's 20-year PPA with Duke Energy expiring on September 30, 2029, which provides up to 30 MW of wind energy from the Silver Sage wind farm to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of the facility's output to South Dakota Electric; and

- Wyoming Electric and South Dakota Electric's Generation Dispatch Agreement requires South Dakota Electric to purchase all of Wyoming Electric's excess energy.

Power Sales Agreements. Our Electric Utilities have various long-term power sales agreements. Key agreements include:

- MDU owns a 25% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, South Dakota Electric will provide MDU with 25 MW from its other generation facilities or from system purchases with reimbursement of costs by MDU;

- South Dakota Electric has an agreement through December 31, 2023 to provide MDU capacity and energy up to a maximum of 50 MW;

- The City of Gillette owns a 23% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, South Dakota Electric will provide the City of Gillette with its first 23 MW from its other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, South Dakota Electric will also provide the City of Gillette its operating component of spinning reserves; and

- South Dakota Electric has an agreement to supply up to 20 MW of energy and capacity to MEAN under a contract that expires in 2023. The terms of the contract run from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2018	20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2020	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2022	12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

- South Dakota Electric has an agreement from January 1, 2017 through December 31, 2021 to provide 50 MW of energy to Cargill (assigned to Macquarie on January 3, 2018) during heavy and light load timing intervals.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission systems composed of high voltage transmission lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2017, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
South Dakota Electric	South Dakota, Wyoming	1,264	2,506
South Dakota Electric - Jointly Owned [(a)]	South Dakota, Wyoming	44	—
Wyoming Electric	South Dakota, Wyoming	49	1,281
Colorado Electric	Colorado	602	3,093

(a) South Dakota Electric owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to both the WECC region in the West and the MAPP region in the East. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. South Dakota Electric's electric system is located in the WECC region. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids.

South Dakota Electric has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the WECC region through 2023.

South Dakota Electric also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming, to serve our power sales contract with MDU through December 31, 2023, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

In order to serve Wyoming Electric's existing load, Wyoming Electric has a network transmission agreement with Western Area Power Association's Loveland Area Project.

Colorado Electric is party to a joint dispatch agreement between Colorado Electric, Public Service Company of Colorado "PSCo" and Platte River Power Authority. This FERC-approved agreement, effective in 2017, is structured to allow PSCo, as administrator, to receive load and generation bid information for all three parties and, on an intra-hour basis, serve the combined utility load utilizing the combined bid generating resources on a least-cost basis. In other words, if one party has excess generation at a lower cost than another party's generation, the administrator will increase dispatch of the lower-cost generation and decrease dispatch of the higher-cost generation. This results in lower energy costs to customers through more efficient dispatch of low-cost generating resources. Under the agreement, Colorado Electric retains the ability to participate or not participate in the joint dispatch at its discretion.

Operating Agreements. Our Electric Utilities have the following material operating agreements:

- Shared Services Agreements -

    South Dakota Electric, Wyoming Electric, and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.

Black Hills Colorado IPP and Colorado Electric are also parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.

South Dakota Electric and Wyoming Electric receive certain staffing and management services from BHSC for Cheyenne Prairie.

- Jointly Owned Facilities -

South Dakota Electric, the City of Gillette and MDU are parties to a shared joint ownership agreement, whereby South Dakota Electric charges the City of Gillette and MDU for administrative services, plant operations and maintenance for their share of the Wygen III generating facility for the life of the plant.

    Colorado Electric and AltaGas are parties to a shared joint ownership agreement whereby Colorado Electric charges AltaGas for operations and maintenance for their share of the Busch Ranch Wind Farm.

Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, demand is often greater in the summer and winter months for cooling and heating, respectively. Because our Electric Utilities have a diverse customer and revenue base, and we have historically optimized the utilization of our electric power supply resources, the impact on our operations may not be as significant when weather conditions are warmer in the winter and cooler in the summer.

Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated independent power producers for the right to provide electric energy and capacity for Colorado Electric when resource plans require additional resources.

Rates and Regulation. Our Electric Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities. The following table provides regulatory information for each of our electric utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms	Percentage of Power Marketing Profit Shared with Customers
South Dakota Electric	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TCA, Energy Efficiency Cost Recovery/DSM	70%
	SD		7.76%			5/2014	Transmission Facility Adjustment (TFA)	N/A
	SD		7.76%			6/2011	Environmental Improvement Adjustment Tariff	N/A
	FERC	10.8%	9.10%	43%/57%		2/2009	FERC Transmission Tariff	N/A
Wyoming Electric	WY	9.9%	7.98%	46%/54%	$376.8	10/2014	PCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
	FERC	10.6%	8.51%	46%/54%	$31.5	5/2014	FERC Transmission Tariff	N/A
Colorado Electric	CO	9.37%	7.43%	47.6%/52.4%	$539.6	1/2017	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment	90%
	CO	9.37%	6.02%	67.3%/32.7%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A

The regulatory provisions for recovering the costs to supply electricity vary by state. In all states, subject to thresholds noted below, we have cost adjustment mechanisms for our Electric Utilities that allow us to pass the prudently-incurred cost of fuel and purchased power through to customers. These mechanisms allow the utility operating in that state to collect, or refund, the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. Some states in which our utilities operate also allow the utility operating in that state to automatically adjust rates periodically for the cost of new transmission or environmental improvements and, in some instances, the utility has the opportunity to earn its authorized return on new capital investment immediately.

The significant mechanisms we have in place include the following by utility and state:

South Dakota Electric has:

- An annual adjustment clause which provides for the direct recovery of increased fuel and purchased power cost incurred to serve South Dakota customers. Additionally, the ECA contains an off-system sales sharing mechanism in which South Dakota customers will receive a credit equal to 100% of off-system power marketing operating income from the first $2 million of power marketing margin from short-term sales and a credit equal to 70% of power marketing margins from short-term sales in excess of the first $2 million. South Dakota Electric retains the additional 30%. The ECA methodology allows us to directly assign renewable resources and firm purchases to the customer load. In Wyoming, a similar fuel and purchased power cost adjustment is also in place.
- An approved annual Environmental Improvement Adjustment (EIA) tariff which recovers costs associated with generation plant environmental improvements. The EIA and TFA were suspended for a six-year period effective July

1, 2017. See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

- An approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric’s open access transmission tariff.

In Wyoming, Wyoming Electric has:

- An annual cost adjustment mechanism that allows us to pass the prudently-incurred costs of fuel and purchased power through to electric customers. The annual cost adjustment allows for recovery of 85% of coal and coal-related cost per kWh variances from base, and recovery of 95% of purchased power, transmission, and natural gas cost per kWh variances from base.

- An approved FERC Transmission Tariff that determines the revenue component of Wyoming Electric’s open access transmission tariff.

In Colorado, Colorado Electric has:

- A quarterly ECA rider that allows us to recover forecasted increases or decreases in purchased energy and fuel costs, including the recovery for amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others, symmetrical interest, and the sharing of off-system sales margins, less certain operating costs (customer receives 90%). The ECA provides for not only direct recovery, but also for the issuance of credits for decreases in purchased energy, fuel costs and eligible energy resources.

- Colorado allows an annual TCA rider that includes nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

- The Clean Air Clean Jobs Act Adjustment rider rate collects the authorized revenue requirement for the 40 MW combustion turbine placed in service on December 31, 2016 with rates effective January 1, 2017.

- The Renewable Energy Standard Adjustment rider is specifically designed for meeting the requirements of Colorado’s renewable energy standard and most recently includes cost recovery for the Peak View Wind Project.

See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information regarding current electric rate activity.

Operating Statistics. The following tables summarize information for our Electric Utilities:

Degree Days	2017		2016		2015	
	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)
Heating Degree Days:						
South Dakota Electric	6,870	(4)%	6,402	(10)%	6,521	(8)%
Wyoming Electric	6,623	(12)%	6,363	(14)%	6,404	(10)%
Colorado Electric	4,693	(16)%	4,658	(16)%	4,846	(12)%
Combined (a)	5,826	(11)%	5,595	(13)%	5,729	(10)%
Cooling Degree Days:						
South Dakota Electric	709	11%	646	(4)%	577	(14)%
Wyoming Electric	429	23%	460	31%	407	16%
Colorado Electric	1,027	14%	1,358	42%	1,270	32%
Combined (a)	798	14%	935	26%	861	16%

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(a) The combined heating degree days are calculated based on a weighted average of total customers by state.
(b) 30-Year Average is from NOAA Climate Normals.

	Electric Revenue (in thousands)			Quantities sold (MWh)		
	2017	2016	2015	2017	2016	2015
Residential	$210,172	$208,725	$209,664	1,390,952	1,395,097	1,399,901
Commercial	258,754	258,768	258,539	2,038,495	2,067,486	2,031,556
Industrial	122,958	118,181	112,255	1,598,755	1,515,553	1,399,641
Municipal	18,144	17,821	17,863	160,882	162,383	159,496
Subtotal Retail Revenue - Electric	610,028	603,495	598,321	5,189,084	5,140,519	4,990,594
Contract Wholesale	30,435	17,037	17,537	722,659	246,630	260,893
Off-system/Power Marketing Wholesale	21,111	22,355	29,726	661,263	769,843	1,000,085
Other	43,076	34,394	34,259	—	—	—
Total Revenue and Energy Sold	704,650	677,281	679,843	6,573,006	6,156,992	6,251,572
Other Uses, Losses or Generation, net	—	—	—	468,179	433,400	414,159
Total Revenue and Energy	704,650	677,281	679,843	7,041,185	6,590,392	6,665,731
Less cost of fuel and purchased power	268,405	261,349	269,409			
Gross Margin	$436,245	$415,932	$410,434			

	Electric Revenue (in thousands)			Gross Margin (a) (in thousands)			Quantities Sold (MWh) (b)		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
South Dakota Electric	$288,433	$267,632	$277,864	$200,795	$192,606	$194,524	3,187,392	2,767,315	3,040,703
Wyoming Electric	165,127	157,606	150,156	89,371	85,036	83,537	1,762,117	1,677,421	1,530,628
Colorado Electric	251,090	252,043	251,823	146,079	138,290	132,373	2,091,676	2,145,656	2,094,400
Total Revenue, Gross Margin, and Quantities Sold	$704,650	$677,281	$679,843	$436,245	$415,932	$410,434	7,041,185	6,590,392	6,665,731

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(a) Non-GAAP measure

(b) Total MWh includes Other Uses, Losses or Generation, net, which is approximately 6%, 7%, and 8% for South Dakota Electric, Wyoming Electric, and Colorado Electric, respectively.

Quantities Generated and Purchased (MWh)	2017	2016	2015
Coal-fired	2,230,617	2,201,757	2,228,377
Natural Gas and Oil	307,815	343,001	230,320
Wind	239,472	80,582	41,043
Total Generated	2,777,904	2,625,340	2,499,740
Purchased	4,263,281	3,965,052	4,165,991
Total Generated and Purchased	7,041,185	6,590,392	6,665,731

Quantities Generated and Purchased (MWh)	2017	2016	2015
Generated:			
South Dakota Electric	1,581,915	1,585,870	1,618,688
Wyoming Electric	798,024	805,351	739,277
Colorado Electric	397,965	234,119	141,775
Total Generated	2,777,904	2,625,340	2,499,740
Purchased:			
South Dakota Electric	1,605,477	1,181,445	1,422,015
Wyoming Electric	964,093	872,070	791,351
Colorado Electric	1,693,711	1,911,537	1,952,625
Total Purchased	4,263,281	3,965,052	4,165,991
Total Generated and Purchased	7,041,185	6,590,392	6,665,731

Customers at End of Year	2017	2016	2015
Residential	179,911	178,333	176,901
Commercial	29,354	29,086	29,172
Industrial	86	88	87
Other	914	1,001	1,027
Total Electric Customers at End of Year	210,265	208,508	207,187

Customers at End of Year	2017	2016	2015
South Dakota Electric	72,184	71,353	70,733
Wyoming Electric	42,130	41,531	41,422
Colorado Electric	95,951	95,624	95,032
Total Electric Customers at End of Year	210,265	208,508	207,187

Gas Utilities Segment

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. On February 12, 2016, we acquired SourceGas Holdings, LLC, adding four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,042,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as available basis.

We also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services has approximately 52,000 retail distribution customers in Nebraska and Wyoming providing unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and appliance protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 63,000 and 31,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements with Colorado Interstate Gas Company, Enable Gas Transmission, Tallgrass Interstate Gas Transmission, Natural Gas Pipeline Company of America, Northern Natural Gas, Panhandle Eastern Pipeline Company, Southern Star Central Gas Pipeline, Black Hills Shoshone Pipeline, TransColorado Gas Transmission, WBI Energy Transmission, Rocky Mountain Natural Gas, Ozark Gas Transmission, Liberty Utilities, Texas Eastern Transmission Pipeline, WestGas InterState Pipeline, Public Service Company of Colorado and Red Cedar Gas Gathering.

In addition to company-owned storage assets in Wyoming, Colorado and Arkansas, we also contract with many of the third-party transportation providers noted above for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas.

The following table summarizes certain information regarding our regulated underground gas storage facilities as of December 31, 2017:

State	Working Capacity (Mcf)	Cushion Gas (Mcf) [(a)]	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	8,442,700	12,950,000	21,392,700	196,000
Colorado	2,360,895	6,165,315	8,526,210	30,000
Wyoming	5,733,900	17,145,600	22,879,500	32,950
Total	16,537,495	36,260,915	52,798,410	258,950

(a) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

The following tables summarize certain operating information for our Gas Utilities.

System Infrastructure (in line miles) as of

December 31, 2017	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	926	4,654	919
Colorado	683	6,569	2,399
Nebraska	1,256	8,467	3,219
Iowa	163	2,777	2,653
Kansas	325	2,855	1,337
Wyoming	1,303	3,396	1,210
Total	4,656	28,718	11,737

Degree Days	2017		2016		2015	
	Actual	Variance From 30-Year Average [d]	Actual	Variance From 30-Year Average [d]	Actual	Variance From 30-Year Average [d]
Heating Degree Days:						
Arkansas [a]	3,295	(19)%	2,397	(41)%	—	—%
Colorado	5,728	(14)%	5,762	(13)%	5,527	(12)%
Nebraska	5,554	(10)%	5,457	(12)%	5,350	(12)%
Iowa	6,149	(9)%	5,997	(11)%	6,629	(2)%
Kansas [a]	4,452	(9)%	4,307	(12)%	4,432	(9)%
Wyoming	7,123	(5)%	6,750	(10)%	6,404	(10)%
Combined [b] [c]	5,862	(10)%	5,823	(11)%	5,890	(8)%

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(a) Kansas and Arkansas have weather normalization mechanisms which mitigate the weather impact on gross margins.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism. Arkansas Gas Distribution is partially excluded based on the weather normalization mechanism in effect from November through April.

(c) To conform to the current year comparisons to normal, the 2016 utility variances compared to normal, as well as the 2016 combined variance compared to normal have been updated.

(d) 30-Year Average is from NOAA climate normals.

Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather throughout our service territories, and as a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation.

Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge for transporting the gas through our distribution network.

Rates and Regulation. Our Gas Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities.

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure that they recover all the costs prudently incurred in purchasing gas for their customers. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to energy efficiency plans and system safety and integrity investments. The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms
Gas Utilities:							
Arkansas Gas [(a)]	AR	9.4%	6.47% [(b)]	52%/48%	$299.4 [(c)]	2/2016	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative/Regulatory Mandate and Relocations Rider, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.6%	8.41%	50%/50%	$64.0	12/2012	GCA, Energy Efficiency Cost Recovery/DSM
Colorado Gas Dist.[(a)]	CO	10.0%	8.02%	49.52%/ 50.48%	$127.1	12/2010	GCA, DSM
RMNG [(a)]	CO	10.6%	7.93%	49.23%/ 50.77%	$90.5	3/2014	System Safety Integrity Rider, Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$109.2	2/2011	GCA, Energy Efficiency Cost Recovery/DSM/Capital Infrastructure Automatic Adjustment Mechanism, Gas Supply Optimization revenue sharing
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.4	1/2015	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension

							Levelized Adjustment
Nebraska Gas	NE	10.1%	9.11%	48%/52%	$161.3	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge
Nebraska Gas Dist. (a)	NE	9.6%	7.67%	48.84%/ 51.16%	$87.6/$69.8 (d)	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice supplier fee
Wyoming Gas	WY	9.9%	7.98%	46%/54%	$59.6	10/2014	GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment
Wyoming Gas Dist. (a)	WY	9.92%	7.98%	49.66%/ 50.34%	$100.5	1/2011	Choice Gas Program, Purchased GCA, Usage Per Customer Adjustment

(a) Acquired through SourceGas

(b) Arkansas return on rate base adjusted to remove current liabilities from rate case capital structure for comparison with other subsidiaries.

(c) Arkansas rate base is adjusted to include current liabilities for comparison with other subsidiaries.

(d) Total Nebraska rate base of $87.6 million includes amounts allocated to serve non-jurisdictional and agricultural customers. Jurisdictional Nebraska rate base of $69.8 million excludes those amounts allocated to serve non-jurisdictional and agricultural customers and is used for calculation of jurisdictional base rates.

All of our Gas Utilities, except where ChoiceGas is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Some of the mechanisms we have in place include the following:

Gas Utility Jurisdiction	Cost Recovery Mechanisms							
	DSM/Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost	Billing Determinant Adjustment	Revenue Decoupling
Arkansas Gas	þ	þ		þ		þ	þ	
Colorado Gas	þ					þ		
Colorado Gas Dist.	þ					þ		
Rocky Mountain Natural Gas	N/A	þ	N/A	N/A	N/A	N/A	N/A	N/A
Iowa Gas	þ	þ				þ		
Kansas Gas		þ	þ	þ	þ	þ		
Nebraska Gas		þ	þ			þ		
Nebraska Gas Dist.		þ	þ			þ		
Wyoming Gas [a]	þ					þ		
Wyoming Gas Dist.						þ		þ

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(a) This is only applicable to Cheyenne Light and does not apply to our other Wyoming gas utilities.

See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current natural gas rate activity.

Operating Statistics

2016 includes results from the acquired SourceGas utilities starting February 12, 2016.

	Revenue (in thousands)			Gross Margin [a] (in thousands)		
	2017	2016	2015	2017	2016	2015
Residential	$499,852	$433,106	$342,145	$255,626	$228,512	$155,759
Commercial	197,054	162,547	117,574	78,249	67,375	38,492
Industrial	24,454	21,245	22,398	6,226	5,601	4,303
Other	8,647	12,694	8,065	8,647	12,694	7,995
Total Distribution	730,007	629,592	490,182	348,748	314,182	206,549
Transportation and Transmission	135,824	139,490	29,816	135,824	139,282	29,816
Total Regulated	865,831	769,082	519,998	484,572	453,464	236,365
Non-regulated Services	81,799	69,261	31,302	53,455	32,714	15,290
Total Revenue & Gross Margin	$947,630	$838,343	$551,300	$538,027	$486,178	$251,655

Revenue (in thousands)

				Gross Margin [a] (in thousands)		
	2017	2016	2015	2017	2016	2015
Arkansas	$153,691	$106,958	$—	$94,007	$69,840	$—
Colorado	180,852	153,003	73,854	100,718	86,016	25,387
Nebraska	252,631	244,992	170,972	154,259	146,831	82,877
Iowa	143,446	130,776	147,952	66,619	64,170	63,496
Kansas	105,576	100,670	114,362	53,841	54,247	57,888
Wyoming	111,434	101,944	44,160	68,583	65,074	22,007
Total Revenue & Gross Margin	$947,630	$838,343	$551,300	$538,027	$486,178	$251,655

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(a) Non-GAAP measure

Gas Utilities Quantities Sold & Transported (Dth)	Quantities 2017	2016	2015
Residential	54,645,598	49,390,451	35,649,700
Commercial	27,315,871	24,037,861	15,765,242
Industrial	5,855,053	5,737,430	5,208,455
Other	—	—	14,902
Total Distribution Quantities Sold	87,816,522	79,165,742	56,638,299
Transportation and Transmission	141,600,080	126,927,565	77,393,775
Total Quantities Sold & Transported	229,416,602	206,093,307	134,032,074

Gas Utilities Quantities Sold & Transported (Dth)	Quantities 2017	2016	2015
Arkansas	26,491,537	19,177,438	—
Colorado	28,436,744	23,656,891	9,288,030
Nebraska	73,890,509	67,796,021	43,992,986
Iowa	37,013,645	35,383,990	35,490,228
Kansas	28,251,947	26,463,314	28,086,737
Wyoming	35,332,220	33,615,653	17,174,093
Total Quantities Sold & Transported	229,416,602	206,093,307	134,032,074

Customers at End of Year	2017	2016	2015
Residential	806,744	800,980	533,413
Commercial	86,461	84,049	50,175
Industrial	2,214	2,050	1,859
Transportation/Other	146,839	143,673	5,962
Total Customers at End of Year	1,042,258	1,030,752	591,409

Customers at End of Year	2017	2016	2015
Arkansas	169,303	166,512	—
Colorado	181,876	177,394	78,434
Nebraska	290,264	289,653	201,261
Iowa	157,444	156,014	155,196
Kansas	114,082	112,957	112,364
Wyoming	129,289	128,222	44,154
Total Customers at End of Year	1,042,258	1,030,752	591,409

Utility Regulation Characteristics

State Regulations

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. As of December 31, 2017, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard that has two components: (i) electric resource standards and (ii) a 2% maximum annual retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We are currently in compliance with these standards.

Colorado Electric received a settlement agreement of its electric resource plan filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. The settlement, effective February 6, 2017, includes the addition of 60 megawatts of renewable energy to be in service by 2019 and provides for additional small solar and community solar gardens as part of the compliance plan. In the second quarter of 2017, Colorado Electric issued a request for proposals to construct new generation and presented the results to the CPUC on February 9, 2018. We expect a final decision from the CPUC in the second quarter of 2018 approving, conditioning, modifying or rejecting Colorado Electric's recommended portfolio.

On November 7, 2016, Colorado Electric took ownership of Peak View, a $109 million, 60 MW wind project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased via progress payments throughout 2016 under a commission approved third-party build transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. The Commission's settlement agreement provides for recovery of the costs of the project through Colorado Electric's Electric Cost Adjustments and Renewable Energy Standard Surcharge for 10 years and recovery through the Transmission Cost Adjustment, after which Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility.

- Montana. In 2005, Montana established a renewable portfolio standard that requires public utilities to obtain a percentage of their retail electricity sales from eligible renewable resources. In March 2013, South Dakota Electric filed a petition with the MTPSC requesting a waiver of the renewable portfolio standards primarily due to exceeding the applicable "cost cap" included in the standards. In March 2013, the Montana Legislature adopted legislation that had the effect of excluding South Dakota Electric from all renewable portfolio standard requirements under State Senate Bill 164, primarily due to the very low number of customers we have in Montana and the relatively high cost of meeting the renewable requirements.

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015.

- Wyoming. Wyoming currently has no renewable energy portfolio standard.

Absent a specific renewable energy mandate in the territories we serve, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers. Mandatory portfolio standards have increased and would likely continue to increase the power supply costs of our Electric Utility operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives. We cannot at this time reasonably forecast the potential costs associated with any new renewable energy standards that have been or may be proposed at the federal or state level.

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities, Black Hills Colorado IPP and Black Hills Wyoming are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. South Dakota Electric owns and operates FERC-jurisdictional interstate transmission facilities and provides open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company with centralized service company subsidiaries, BHSC and Black Hills Utility Holdings, we are subject to FERC's authority under PUHCA 2005.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2017, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of approximately 269 MW.

We produce electric power from our generating plants and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a substantial majority of our non-regulated generating capacity under contracts having terms greater than one year.

As of December 31, 2017, the power plant ownership interests held by our Power Generation segment included:

Power Plants	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [(a)]	Gas	Pueblo, Colorado	50.1%	200.0	2012
				268.9	

(a) Black Hills Colorado IPP owns and operates this facility. This facility provides capacity and energy to Colorado Electric under a 20-year PPA with Colorado Electric. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%. We sell 60 MW of unit-contingent capacity and energy from this plant to Wyoming Electric under a PPA that expires on December 31, 2022. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price related to the option is $2.6 million per MW (65 MWs), adjusted for all depreciated capital additions since 2009, and reduced by depreciation (approximately $5 million per year) over a 35-year life beginning January 1, 2009. The net book value of Wygen I at December 31, 2017 was $69 million and if Wyoming Electric had exercised the purchase option at year-end 2017, the estimated purchase price would have been approximately $133 million. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical to do so.

Black Hills Colorado IPP - Pueblo Airport Generation. The Pueblo Airport Generating Station consists of two 100 MW combined-cycle gas-fired power generation plants located at a site shared with Colorado Electric. The plants commenced operation on January 1, 2012 and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric, which expires on December 31, 2031. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of Colorado Electric.

Sale of Noncontrolling Interest in Subsidiary

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes. The operating results for Black Hills Colorado IPP remain consolidated with Black Hills Electric Generation, as Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) (a)	2017	2016	2015
Sold			
Black Hills Colorado IPP (b)	943,618	1,223,949	1,133,190
Black Hills Wyoming (c)	645,810	644,564	663,052
Total Sold	1,589,428	1,868,513	1,796,242
Generated			
Black Hills Colorado IPP (b)	943,618	1,223,949	1,133,190
Black Hills Wyoming	577,124	543,546	561,930
Total Generated	1,520,742	1,767,495	1,695,120
Purchased			
Black Hills Wyoming (b)	69,377	85,993	68,744
Total Purchased	69,377	85,993	68,744

(a) Company use and losses are not included in the quantities sold, generated and purchased.
(b) The decrease in 2017 is driven by the joint dispatch agreement Colorado Electric joined in 2017. See details of this agreement above in the Electric Utilities segment.
(c) Under the 20-year economy energy PPA with the City of Gillette, effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette.

Operating Agreements. Our Power Generation segment has the following material operating agreements:

- Economy Energy PPA and other ancillary agreements

Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, and provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- Operating and Maintenance Services Agreement

In conjunction with the sale of the noncontrolling interest on April 14, 2016, an operating and maintenance services agreement was entered into between Black Hills Electric Generation and Black Hills Colorado IPP. This agreement sets forth the obligations and responsibilities of Black Hills Electric Generation as the operator of the generating facility owned by Black Hills Colorado IPP. This agreement is in effect from the date of the noncontrolling interest purchase and remains effective as long as the operator or one of its affiliates is responsible for managing the generating facilities in accordance with the noncontrolling interest agreement, or until termination by owner or operator.

- Shared Services Agreements

South Dakota Electric, Wyoming Electric and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.

Black Hills Colorado IPP and Colorado Electric are parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.

Black Hills Colorado IPP, Wyoming Electric and South Dakota Electric are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges South Dakota Electric and Wyoming Electric a monthly fee for the availability of a spare turbine to support the operation of Cheyenne Prairie Generating Station.

Black Hills Colorado IPP and Black Hills Wyoming receive certain staffing and management services from BHSC.

- Jointly Owned Facilities

Black Hills Wyoming and MEAN are parties to a shared joint ownership agreement, whereby Black Hills Wyoming charges MEAN for administrative services, plant operations and maintenance on their share of the Wygen I generating facility over the life of the plant.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own two EWGs: Wygen I and 200 MW (two 100 MW combined-cycle gas-fired units) at the Pueblo Airport Generating Station. Our EWGs were granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Mining Segment

Our Mining segment operates through our WRDC subsidiary. We surface mine, process and sell primarily low-sulfur sub-bituminous coal at our mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.2 million tons of coal in 2017.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden typically requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we re-establish vegetation and plant life in accordance with our approved post-mining topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended upwards. The overburden ratio at December 31, 2017 was 2.16, which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to be approximately 2.15 by the end of 2018 as we mine in areas with comparable overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between April 30, 2019 and September 30, 2025 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2017, we estimated our recoverable coal reserves to be approximately 195 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable coal reserve life is equal to approximately 47 years at the current production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Mining for further details.

Substantially all of our coal production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant. This contract is for the life of the plant;
- Wyoming Electric for use at the 95 MW Wygen II plant. This contract is for the life of the plant;
- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. South Dakota Electric is also obligated to purchase a minimum of 0.375 million tons of coal per year for its 20% share of the power plant. This contract expires December 31, 2022;
- The 110 MW Wygen III power plant owned 52% by South Dakota Electric, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons of coal each year. This contract expires June 1, 2060;
- The 90 MW Wygen I power plant owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons of coal each year. This contract expires June 30, 2038; and
-

Certain regional industrial customers served by truck to which we sell a total of approximately 150,000 tons of coal each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric for all of their requirements under cost-based agreements that regulate earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return calculated annually is 400 basis points above A-rated utility bonds applied to our Mining investment base. South Dakota Electric made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for South Dakota Electric's operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant and through June 1, 2060, for Wygen III. The agreement with Wyoming Electric provides coal for the life of the Wygen II plant.

The price of unprocessed coal sold to PacifiCorp for the Wyodak plant is determined by the coal supply agreement described above. The agreement includes a price adjustment in 2019. The price adjustment essentially allows us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustment is based on the market price of coal plus considerations for the avoided costs of rail transportation and a coal unloading facility, which PacifiCorp would have to incur if it purchased coal from another mine. In addition, the agreement also provides for the monthly escalation of coal price based on an escalation factor.

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement using a base price that includes price escalators and quality adjustments through June 30, 2038 and includes actual cost per ton plus a margin equal to the yield for Moody's A-Rated 10-Year Corporate Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen I plant through June 30, 2038.

Competition. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, off-site sales have been to consumers within a close proximity to the mine. Rail transport market opportunities for WRDC coal are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC coal mine is served by only one railroad, resulting in less competitive transportation rates. Management continues to explore the limited market opportunities for our product through truck transport.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental considerations and availability affect the overall demand for coal as a fuel.

Environmental Matters. We are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. See Environmental Matters section for further information.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five-year mining permit issued by the State of Wyoming. In 2016, that five-year permit was re-issued. Based on extensive reclamation studies, we have accrued approximately $12 million for reclamation costs as of December 31, 2017. Mining regulatory requirements continue to increase, which impose additional cost on the mining process.

Environmental Matters

At Black Hills, we deliver energy to our customers and communities guided by our commitment to environmental stewardship; to sustain environmental compliance which results in healthier communities.

South Dakota and Wyoming Power Generation. Based on current regulations, technology and plans, the following table contains our current estimates of capital expenditures expected to be incurred over the next three years to comply with current environmental laws and regulations as described below, including regulations that cover water, air, soil and other pollutants, but excluding plant closures and the cost of new generation. The ultimate cost could be significantly different from the amounts estimated.

Environmental Expenditure Estimates	Total (in thousands)
2018	$ 3,086
2019	1,674
2020	611
Total	$ 5,371

Methane Rules (Greenhouse Gas Emissions). The EPA and the State of Colorado have implemented strict regulatory requirements on fugitive methane emissions associated with oil and natural gas exploration and production operations and from natural gas gathering and transmission systems. Additionally, the BLM issued a new rule referred to as the Methane Rule (aka Venting and Flaring rule) with the intent to capture methane leaks and lost royalties from companies that operate on federal land.

The rule has been postponed for one year by the BLM, but continues to be legally contested. While this risk is substantially reduced through the divestiture of BHEP, it continues to impact our remaining natural gas gathering and transmission operations. It is anticipated that regulatory control in this area may continue to expand, affecting a larger portion of Black Hills' natural gas operations, including storage and distribution. Presently, we have seven compressor stations in our natural gas transmission operations affected by the rule (one in Arkansas, three in Colorado, and three in Wyoming).

Our operations are currently in compliance with both EPA and BLM rules. Although the BLM rule has been postponed, non- compliance would expose us to both enforcement action and civil suits. We will continue to monitor the litigation until the BLM's rule status is clarified through the resolution of legal challenges. Additionally, we are developing a corporate-wide methane control strategy to address GHG emissions from our natural gas operations.

Water Issues. Our facilities are subject to a variety of state and federal regulations governing existing and potential water/ wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through EPA's surface water discharge and storm water permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. The EPA proposed effluent limitation guidelines and standards on June 7, 2013 and published the final rule on November 3, 2015. This rule will have an impact on the Wyodak Plant. The terms of this new regulation impact the next permit renewal, which will be in 2020. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities subject to these regulations have compliant prevention plans in place.

Short-term Emission Limits. The EPA and State Air Quality Programs implemented short-term emission limits for coal and natural gas-fired generating units during normal and start-up operating scenarios for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x) and Opacity. The limits pertain to emissions during start-up periods and upset conditions such as mechanical malfunctions. State and federal regulatory agencies typically excuse short-term emissions exceedances if they are reported and corrected immediately or if it occurs during start-up.

We proactively manage this requirement through maintenance efforts and installing additional pollution control systems to control SO2 emission short-term excursions during start-up. These actions have nearly eliminated our short-term emission limit compliance risk while plant availability remained above 90% for all four of our coal-fired plants at the Neil Simpson Complex. To eliminate the remaining potential for exceedances, an innovative trip logic mechanism was implemented to shut the power plant down if a predicted emission limit is to be exceeded. Similar efforts have been taken and similar results achieved with our natural gas fired combustion turbine sites as well.

Regional Haze (Impacts to the Wyodak Power Plant). The EPA Regional Haze rule was promulgated to improve visibility in our National Parks and Wilderness Areas. The State of Wyoming proposed controls in its Regional Haze State Implementation Plan (SIP) which allowed Pacificorp to install low-NO_x burners in its Wyodak Plant. The EPA did not agree with the State of Wyoming's determination and overruled it in a Federal Implementation Plan (FIP). The State of Wyoming and other interested parties are challenging the EPA's determination. If the challenge is unsuccessful, additional capital investment would be necessary to bring the Wyodak Plant into compliance. Our share of this capital investment would be approximately $40 million.

Mining. Operations at the WRDC mine must regularly address issues related to the proximity of the mine disturbance boundary to the City of Gillette, and to residential and industrial properties. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential areas. Specific concerns could include damage to wells, fugitive dust emissions, vibration and an emissions cloud from blasting.

Former Manufactured Gas Plants (FMGP). Federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. Our gas utilities are managing FMGP sites in Iowa, Nebraska and Colorado. We are currently in discussions with EPA, state regulators, and/or other third-parties to determine the ultimate resolution to these sites.

Clean Power Plan. The EPA was directed to repeal, revise, and replace the Clean Power Plan rule. The EPA issued two public notices in the Federal Register late in 2017. The first identified the EPA's intent to repeal the rule and the second was issued to seek public input on proposals to replace the CPP with an Advanced Notice of Proposed Rule Making (ANPRM). Natural gas and renewable generation industries are pushing the EPA to replace the current rule. We will continue to monitor and comment on the proposals and take appropriate action related to any new or modified rules.

OSM Coal Combustion Residual Rule (CCR). The EPA issued the CCR that is currently effective and established requirements to protect surface and groundwater from impacts of coal ash impoundments. WRDC is exempt from the EPA CCR because coal ash is used for backfill reclamation in the areas previously mined. We would be subject to any proposed OSM CCR.

During the development of the OSM rule, it was anticipated that placing ash below groundwater levels would be disallowed. While our mining operations place ash below groundwater levels, the State of Wyoming gave us approval to grandfather this ash disposal in the Peerless Pit, with the Mine Plan Permit 232-T8, as a potential preventative measure to a new rule. As such, any risks associated with having to construct a new ash disposal site above groundwater and then complete backfilling the existing ash pit area to required reclamation levels are not applicable at this time.

Oil and Gas Segment Divestiture. Regulatory agencies placed a significant emphasis on regulating oil and gas activities over the past few years to address GHG and climate change concerns mainly due to the associated methane emissions. The regulatory activity significantly increased compliance risk. We will see relief in our compliance risk concerns with the divestiture of our oil and gas segment in 2018.

Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We assess risk annually and develop mitigation strategies to successfully and responsibly manage and ensure compliance across the enterprise. For additional information on environmental matters, see Item 1A and Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Other Properties

In addition to the facilities previously disclosed in Items 1 and 2, we own or lease several facilities throughout our service territories. Our owned facilities are as follows:

- In Rapid City, South Dakota, we have a new 220,000 square foot corporate headquarters building, Horizon Point, which was completed in the fourth quarter of 2017.

- In Arkansas, Nebraska, Iowa, Colorado, Kansas and Wyoming we own various office, service center, storage, shop and warehouse space totaling over 717,000 square feet utilized by our Gas Utilities.

- In South Dakota, Wyoming, Colorado and Montana we own various office, service center, storage, shop and warehouse space totaling approximately 237,000 square feet utilized by our Electric Utilities and Mining segments.

In addition to our owned properties, we lease 270,925 square feet of properties within our service areas.

Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

Employees

At December 31, 2017, we had 2,744 full-time employees in continuing operations. Approximately 27% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2017, approximately 24% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement.

The following table sets forth the number of employees included in continuing operations:

	Number of Employees
Corporate	484
Electric Utilities and Gas Utilities	2,199
Mining and Power Generation	61
Total	2,744

At December 31, 2017, certain employees of our Electric Utilities and Gas Utilities were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
South Dakota Electric [(a)]	131	IBEW Local 1250	March 31, 2022
Wyoming Electric	42	IBEW Local 111	June 30, 2019
Colorado Electric	103	IBEW Local 667	April 15, 2018
Iowa Gas	115	IBEW Local 204	July 31, 2020
Kansas Gas [(c)]	17	Communications Workers of America, AFL-CIO Local 6407	December 31, 2019
Nebraska Gas	99	IBEW Local 244	March 13, 2022
Nebraska Gas [(b)]	143	CWA Local 7476	October 30, 2019
Wyoming Gas [(b)]	86	CWA Local 7476	October 30, 2019
Total	736		

(a) On January 26, 2017, South Dakota Electric's contract was ratified with an expiration date of March 31, 2022.
(b) In the 2016 negotiations with the CWA Local 7476, the union agreed to disclaim their interest in Colorado Gas employees and to split the remaining bargaining unit into two distinct bargaining units, Nebraska Gas and Wyoming Gas.
(c) Kansas Gas completed a wage adjustment that was ratified on November 15, 2017.

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. The following risk factors and other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company. These important factors and other matters discussed herein could cause our future actual results or outcomes to differ materially.

OPERATING RISKS

Our financial performance depends on the successful operation of our facilities. If the risks involved in our operations are not appropriately managed or mitigated, our operations may not be successful and this could adversely affect our results of operations.

Operating electric generating facilities, the coal mine and electric and natural gas distribution systems involves risks, including:

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted, our ability to sell or deliver product and satisfy our contractual obligations may be hindered;

- Interruptions to supply of fuel and other commodities used in generation and distribution. Our utilities purchase fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations, which could limit our utilities' ability to operate their facilities;

- Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical service facilities and equipment. Natural conditions and other disasters such as wind, lightning and winter storms can cause wildfires, pole failures and associated property damage and outages;

- Operating hazards such as leaks, mechanical problems and accidents, including explosions, affecting our natural gas distribution system which could impact public safety, reliability and customer confidence;

- Operational limitations imposed by environmental and other regulatory requirements;

- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak Plant;

- Labor relations. Approximately 27% of our employees are represented by a total of eight collective bargaining agreements;

- Our ability to transition and replace our retirement-eligible utility employees. At December 31, 2017, approximately 24% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement;

- Inability to recruit and retain skilled technical labor; and

- Disruption in the functioning of our information technology and network infrastructure which are vulnerable to disability, failures and unauthorized access. If our information technology systems were to fail and we were unable to recover in a timely manner, we would be unable to fulfill critical business functions.

Changes in the interpretation of the Tax Cuts and Jobs Act (“TCJA”) could adversely affect us.

On December 22, 2017, the TCJA was signed into law, significantly reforming the U.S. Internal Revenue Code. The TCJA, among other things, includes a decrease in the U.S. federal corporate tax rate from 35% to 21%, imposes significant additional limitations on the deductibility of interest, allows for the expensing of capital expenditures, and modifies or repeals many business deductions and credits. The new tax law contains several provisions that impacted our 2017 financial results and will impact the Company into the future. As allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Company has recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation, for which the impacts could not be finalized upon issuance of the Company’s financial statements but reasonable estimates could be determined.

In accordance with ASC 740, the enactment of the law on December 22, 2017 required revaluation of federal deferred tax assets and liabilities using the new lower corporate statutory tax rate of 21%. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA. On a consolidated financial statement basis, the revaluation of deferred tax assets and liabilities to the 21% federal corporate tax rate that are not subject to the regulatory construct resulted in a one-time, non-cash, income tax benefit of approximately $8 million in 2017.

The TCJA includes provisions limiting interest deductibility in certain circumstances. While we expect to maintain deductibility of interest expense, the lower tax rate reduces the tax benefits associated with interest deductibility on holding company debt that is not recovered in the regulatory construct.

We are working with utility regulators in each of the states we serve to provide benefits of tax reform to our customers. We expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers. The lower tax rate effective January 1, 2018, will negatively impact the Company’s cash flows by approximately $35 million to $45 million annually for the next several years.

If we are unable to obtain reasonable outcomes with our utility regulators in passing benefits of the TCJA back to customers, or if our interpretations on the provisions of depreciation or interest deductibility in the TCJA change, our results of operations, financial position and cash flows could be materially impacted.

Construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve significant risks which could reduce profitability.

The construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve many risks, including:

- The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals;
- Contractual restrictions upon the timing of scheduled outages;
- The cost of supplying or securing replacement power during scheduled and unscheduled outages;
- The unavailability or increased cost of equipment;
- The cost of recruiting and retaining or the unavailability of skilled labor;
- Supply interruptions, work stoppages and labor disputes;
- Increased capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- Availability and cost of fuel supplies;

- Unexpected engineering, environmental and geological problems; and

- Unanticipated cost overruns.

The ongoing operation of our facilities involves many of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, including newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could reduce revenues, increase expenses or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

Operating results can be adversely affected by variations from normal weather conditions.

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters therefore could have an adverse effect on our results of operations, financial position and cash flows.

Our businesses are located in areas that could be subject to seasonal natural disasters such as severe snow and ice storms, flooding and wildfires. These events could result in interruption of our business, damage to our property such as power lines and substations, and repair and clean-up costs. We may not be able to recover the costs incurred in restoring transmission and distribution property following these natural disasters through a change in our regulated rates thereby resulting in a negative impact on our results of operations, financial position and cash flows.

Our Mining operations are subject to operating risks that are beyond our control which could affect our profitability and production levels. Our surface mining operations could be disrupted or materially affected due to adverse weather or natural disasters such as heavy snow, strong winds, rain or flooding.

Prices for some of our products and services as well as a portion of our operating costs are volatile and may cause our revenues and expenses to fluctuate significantly.

A portion of our net income is attributable to sales of contract and off-system wholesale electricity and natural gas. Energy prices are influenced by many factors outside our control, including, among other things, fuel prices, transmission constraints, supply and demand, weather, general economic conditions, and the rules, regulations and actions of system operators in those markets. Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets may be subject to significant, unpredictable price fluctuations over relatively short periods of time.

Our Mining operations require reliable supplies of replacement parts, explosives, fuel, tires and steel-related products. If the cost of these increase significantly, or if sources of supplies and mining equipment become unavailable to meet our replacement demands, our productivity and profitability could be lower than our current expectations.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions, emerging technologies or responses to price increases.

Our revenues, results of operations and financial condition are impacted by demand in our service territories. Customer growth and usage may be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us would decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors could materially affect our results of operations, financial position and cash flows.

Our operations rely on storage and transportation assets owned by third parties to satisfy our obligations.

Our Electric Utilities, Gas Utilities and Power Generation segments rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to customers, to supply our natural gas-fired power plants and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered. As a result, we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates, or for penalties imposed by state regulatory authorities.

Our utilities are subject to pipeline safety and system integrity laws and regulations that may require significant capital expenditures or significant increases in operating costs.

Compliance with pipeline safety and system integrity laws and regulations, or future changes in these laws and regulations, may result in increased capital, operating and other costs which may not be recoverable in a timely manner from customers in rates. Failure to comply may result in fines, penalties, or injunctive measures that would not be recoverable from customers in rates and could result in a material impact on our results of operations, financial position and cash flows.

Our energy production, transmission and distribution activities, and our storage facilities for our natural gas involve numerous risks that may result in accidents and other catastrophic events that could give rise to additional costs and cause a substantial loss to us.

Inherent in our natural gas and electricity transmission and distribution activities, as well as in our transportation and storage of natural gas and our Mining operations, are a variety of hazards and operating risks, such as leaks, blowouts, fires, releases of hazardous materials, explosions and operational problems. These events could impact the safety of employees or others and result in injury or loss of human life, and cause significant damage to property or natural resources (including public lands), environmental pollution, impairment of our operations and substantial financial losses to us. Particularly for our transmission and distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the damages resulting from any such events could be substantial. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events not fully covered by our insurance could have a material adverse effect on our financial position, results of operations or cash flows.

Threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our businesses, or the businesses of third parties, may impact our operations in unpredictable ways.

Terrorist acts or other similar events could harm our businesses by limiting their ability to generate, purchase or transmit power and by delaying their development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets and could adversely affect our operations by contributing to disruption of supplies and markets for natural gas, oil and other fuels. They could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could materially adversely affect our financial results. In addition, these types of events could require significant management attention and resources and could adversely affect our reputation among customers and the public.

A cyber attack may disrupt our operations, or lead to a loss or misuse of confidential and proprietary information and create a potential liability.

We use and operate sophisticated information technology systems and network infrastructure. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees. Cyber attacks targeting our electronic control systems used at our generating facilities and for electric and gas distribution systems, could result in a full or partial disruption of our electric and/or gas operations. Cyber attacks targeting other key information technology systems could further add to a full or partial disruption of our operations. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. Any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data as a result of a cyber attack could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. The security measures and safeguards we have implemented may not always be effective due to the evolving nature and sophistication of cyber attacks. Despite our implementation of security measures and safeguards, all of our information technology systems are vulnerable to disability, failures or unauthorized access, including cyber attacks. If our information technology systems were to fail or be breached by a cyber attack or a computer virus and be unable to recover in a timely way, we would be unable to fulfill critical business functions and sensitive confidential and other data could be compromised which could have a material adverse effect not only on our financial results, but on our public reputation as well.

Increased risks of regulatory penalties could negatively impact our results of operations, financial position or liquidity.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Agencies that historically sought voluntary compliance, or issued non-monetary sanctions, now employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, CFTC, EPA, OSHA, SEC and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our operations and/or our financial results.

Certain Federal laws, including the Migratory Bird Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for non-permitted activities that result in harm to or harassment of certain protected animals, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly transmission, generation, wind and pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures.

Our current or future development and expansion activities may not be successful, which could impair our ability to execute our growth strategy.

Execution of our growth plan is dependent on successful ongoing and future development and expansion activities. We can provide no assurance that we will be able to complete development projects or expansion activities we undertake or continue to develop attractive opportunities for growth. Factors that could cause our development and expansion activities to be unsuccessful include:

- Our inability to obtain required governmental permits;
- Our inability to secure adequate utility rates through regulatory proceedings;
- Our inability to obtain financing on acceptable terms, or at all;
- The possibility that one or more credit rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;
- Our inability to attract and retain management or other key personnel;
- Our inability to negotiate acceptable construction, fuel supply, power sales or other material agreements;
- Reduced growth in the demand for utility services in the markets we serve;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves or our power generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints;

- Competition within our industry and with producers of competing energy sources; and
- Changes in tax rates and policies.

Utilities

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and therefore are not recoverable.

Our regulated Electric Utilities and Gas Utilities are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our direct and allocated borrowing and debt service costs, to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) without having to file a rate case. To the extent we are able to pass through such costs to our customers and a state public utility commission subsequently determines that such costs should not have been paid by the customers; we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect our results of operations, financial position or cash flows.

If market or other conditions adversely affect operations or require us to make changes to our business strategy in any of our utility businesses, we may be forced to record a non-cash goodwill impairment charge. Any significant impairment of our goodwill related to these utilities would cause a decrease in our assets and a reduction in our net income and shareholders’ equity.

We had approximately $1.3 billion of goodwill on our consolidated balance sheets as of December 31, 2017. A substantial portion of the goodwill is related to the SourceGas Acquisition and the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders’ equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

Municipal governments may seek to limit or deny franchise privileges which could inhibit our ability to secure adequate recovery of our investment in assets subject to condemnation.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

Mining

If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, our costs could be significantly greater than anticipated or be incurred sooner than anticipated.

We conduct surface mining operations that are subject to operations, reclamation and closure standards. We estimate our total reclamation liabilities based on permit requirements, engineering studies and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers and by government regulators. The estimated liability can change significantly if actual costs vary from our original assumptions or if government regulations change significantly. GAAP requires that asset retirement obligations be recorded as a liability based on fair value, which reflects the present value of the estimated future cash flows. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates. The resulting estimated reclamation obligations could change significantly if actual amounts or the timing of these expenses change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial position.

Estimates of the quality and quantity of our coal reserves may change materially due to numerous uncertainties inherent in three-dimensional structural modeling, and any inaccuracies in interpretation or modeling could materially affect the estimated quantity and quality of our reserves.

The process of estimating coal reserves is uncertain and requires interpretations and modeling. Significant inaccuracies in interpretation or modeling could materially affect the quantity and quality of our reserve estimates. The accuracy of reserve estimates is a function of engineering and geological interpretation, conditions encountered during actual reserve recovery and undetected deposit anomalies. Variance from the assumptions used and drill hole modeling density could result in additions or deletions from our volume estimates. In addition, future environmental, economic or geologic changes may occur or become known that require reserve revisions either upward or downward from prior reserve estimates.

FINANCING RISKS

Our credit ratings could be lowered below investment grade in the future. If this were to occur, it could impact our access to capital, cost of capital and other operating costs.

Our issuer credit rating is Baa2 (Stable outlook) by Moody’s; BBB (Stable outlook) by S&P; and BBB+ (Stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on reasonable terms, or at all. A credit rating downgrade, particularly to a sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

Derivatives regulations could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared resulting in a requirement to post cash collateral (commonly referred to as “margin”) for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users such as utilities and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use natural gas derivative instruments for our hedging activities for our Gas and Electric Utilities' operations. We may also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. As a result of Dodd-Frank regulations promulgated by the CFTC, we may be required to post collateral to clearing entities for certain swap transactions we enter into. In addition our exchange-traded futures contracts are subject to futures margin posting requirements, which could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results due to accounting requirements associated with such activities.

We use various financial contracts and derivatives, including futures, forwards, options and swaps to manage commodity price and financial market risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the commodities or assets being hedged. The difference in accounting can result in volatility in reported results, even though the expected profit margin may be essentially unchanged from the dates the transactions were consummated.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the potential adverse effects resulting from changes in commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Market performance or changes in other assumptions could require us to make significant unplanned contributions to our pension plans and other postretirement benefit plans. Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or liquidity.

As discussed in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan (the pension plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria) and several defined post-retirement healthcare plans and non-qualified retirement plans that cover certain eligible employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to these plans. These estimates and assumptions may change based on actual return on plan assets, changes in interest rates and any changes in governmental regulations.

We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries.

As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds.

There is no assurance as to the amount, if any, of future dividends because they depend on our future earnings, capital requirements and financial condition and are subject to declaration by the Board of Directors. Our operating subsidiaries have certain restrictions on their ability to transfer funds in the form of dividends or loans to us. See "Liquidity and Capital Resources" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings, and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices, and general economic and market conditions.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts, which could adversely affect our results of operations, financial position and liquidity.

A future recession may lead to an increase in late payments from retail, commercial and industrial utility customers, as well as from our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. Our insurance coverage may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting insurance businesses, international, national, state or local events, as well as the financial condition of insurers. Insurance coverage may not continue to be available at all, or at rates or on terms similar to those presently available to us. A loss for which we are not fully insured could materially and adversely affect our financial results. Our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject, including but not limited to environmental hazards, fire-related liability from natural events or inadequate facility maintenance, distribution property losses, cyber-security risks and dangers that exist in the gathering and transportation of gas in pipelines.

Increasing costs associated with our health care plans and other benefits may adversely affect our results of operations, financial position or liquidity.

The costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Significant regulatory developments have, and likely will continue to, require changes to our current employee benefit plans and in our administrative and accounting processes, as well as changes to the cost of our plans, and the increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position or liquidity.

Our electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, there can be no assurance that the state public utility commissions will allow recovery.

An effective system of internal control may not be maintained, leading to material weaknesses in internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to make an assessment of the design and effectiveness of internal controls. Our independent registered public accounting firm is required to attest to the effectiveness of these controls. During their assessment of these controls, management or our independent registered public accounting firm may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material weakness in internal control exists. Any control deficiencies we identify in the future could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system’s objectives will be met. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

ENVIRONMENTAL RISKS

Federal and state laws concerning GHG regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming and Colorado. Developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants may result in more stringent emission limitations, which could have a material impact on our costs of operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the section "Environmental Matters."

Due to uncertainty as to the final outcome of federal climate change legislation, legal challenges, state clean power plan developments or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, cash flows or financial position.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or reduction of load of coal-fired power generation facilities and potential increased load of our combined cycle natural gas-fired generation units. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

The costs to achieve or maintain compliance with existing or future governmental laws, regulations or requirements, and any failure to do so, could adversely affect our results of operations, financial position or liquidity.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

The business segments may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact..

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization and the use of alternative energy sources for power generation as mandated by states could reduce coal consumption.

Future regulations may require further reductions in emissions of mercury, hazardous pollutants, SO_2, NO_x, volatile organic compounds, particulate matter and GHG, which are released into the air when coal is burned. These requirements could require the installation of costly emission control technology or the implementation of other measures. Reductions in mercury emissions required by EPA's MATS rule, will likely require some power plants to install new equipment, at substantial cost, or discourage the use of certain coals containing higher levels of mercury.

Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. The EPA was directed to repeal, revise and replace the CPP rule. At this time, it is not known what effect this will have on coal as a domestic energy source, and could have a significant impact on our mining operations.

Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our operations and financial results could be adversely impacted.

Oil and Gas (Discontinued Operations)
If the risks involved in our Oil and Gas operations are not appropriately managed or mitigated through final sale dates, or if the divestiture of this business segment does not occur as currently anticipated, we could incur costs and/or additional write-downs of the carrying value of our natural gas and oil properties.
As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90 percent of our oil and gas properties. We expect to conclude the sale of all of our remaining oil and gas assets by mid-year 2018. Until the sale transactions are final, we continue to own and operate these assets and are exposed to the risks associated with those operations. In addition, while we have signed agreements for the significant majority of the properties, until the sales are closed, there is a risk that the transactions do not occur as planned. Additional operating costs, additional write-down of carrying value or the non-closure of sale agreements as currently signed could result in an adverse impact to our financial results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” sub-caption within Item 8, Note 19, “Commitments and Contingencies”, of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Annual Report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of December 31, 2017, we had 3,732 common shareholders of record and approximately 25,000 beneficial owners, representing all 50 states, the District of Columbia and 7 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 31, 2018 meeting, our Board of Directors declared a quarterly dividend of $0.475 per share, equivalent to an annual dividend of $1.90 per share. The 2018 equivalent rate of $1.90 per share would mark 2018 as the 48th consecutive annual dividend increase for the Company.

For additional discussion of our dividend policy and factors that may limit our ability to pay dividends, see "Liquidity and Capital Resources" under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K.

Quarterly dividends paid and the high and low prices for our common stock, as reported in the New York Stock Exchange Composite Transactions, for the last two years were as follows:

Year ended December 31, 2017	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.445	$ 0.445	$ 0.445	$ 0.475
Common stock prices				
High	$ 67.02	$ 72.02	$ 71.01	$ 69.79
Low	$ 60.02	$ 65.37	$ 67.08	$ 57.01

Year ended December 31, 2016	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.420	$ 0.420	$ 0.420	$ 0.420
Common stock prices				
High	$ 61.13	$ 63.53	$ 64.58	$ 62.83
Low	$ 44.65	$ 56.16	$ 56.86	$ 54.76

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2017.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the twelve months

ended
December
31, 2017.

ITEM 6. SELECTED FINANCIAL DATA

(Minor differences may result due to rounding)

Years Ended December 31, (dollars in thousands, except per share amounts)	2017		2016		2015		2014		2013	
Total Assets	$6,658,902		$6,541,773		$4,626,643		$4,216,752		$3,820,875	
Property, Plant and Equipment										
Total property, plant and equipment	$5,567,518		$5,315,296		$3,849,309		$3,606,931		$3,412,623	
Accumulated depreciation and depletion	(1,026,088)		(929,119)		(794,695)		(714,762)		(687,010)	
Total property, plant and equipment, net	$4,541,430		$4,386,177		$3,054,614		$2,892,169		$2,725,613	
Capital Expenditures										
Continuing Operations	$337,689		$460,450		$289,896		$281,828		$314,847	
Discontinued Operations	23,222		6,669		168,925		109,439		64,687	
Total Capital Expenditures	$360,911		$467,119		$458,821		$391,267		$379,534	
Capitalization (excluding noncontrolling interests)										
Current maturities of long-term debt	$5,743		$5,743		$—		$275,000		$—	
Notes payable	211,300		96,600		76,800		75,000		82,500	
Long-term debt, net of current maturities and deferred financing costs	3,109,400		3,211,189	(a)	1,853,682		1,255,953		1,383,714	
Common stock equity	1,708,974		1,614,639	(b)	1,465,867	(b)	1,353,884		1,283,500	
Total capitalization	$5,035,417		$4,928,171		$3,396,349		$2,959,837		$2,749,714	
Capitalization Ratios										
Short-term debt, including current maturities	4 %		2 %		2 %		12 %		3 %	
Long-term debt, net of current maturities	62 %		65 %	(a)	55 %		42 %		50 %	
Common stock equity	34 %		33 %		43 %		46 %		47 %	
Total	100 %		100 %		100 %		100 %		100 %	
Total Operating Revenues	$1,680,266		$1,538,916		$1,261,322		$1,338,456		$1,220,968	
Net Income Available for Common Stock										
Electric Utilities	$110,082		$85,827		$77,579		$57,270		$49,003	
Gas Utilities	65,795		59,624		39,306		44,151		35,838	
Power Generation	46,479	(c)	25,930	(c)	32,650		28,516		16,288	(c)
Mining	14,386		10,053		11,870		10,452		6,327	
Corporate and intersegment eliminations	(42,609)	(d)	(44,302)	(d)	(19,857)	(d)	(7,927)		5,855	(d)
	194,133		137,132		141,548		132,462		113,311	

Income (loss) from continuing operations available for common stock										
Income (loss) from discontinued operations, net of tax [b]	(17,099	)	(64,162	)	(173,659	)	(1,573	)	4,112	[e]
Net income (loss) available for common stock	$177,034		$72,970		$(32,111	)	$130,889		$117,423	

SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2017	2016	2015	2014	2013
Dividends Paid on Common Stock	$96,744	$87,570	$72,604	$69,636	$67,587
Common Stock Data[f] (in thousands)					
Shares outstanding, average basic	53,221	51,922	45,288	44,394	44,163
Shares outstanding, average diluted	55,120	53,271	45,288	44,598	44,419
Shares outstanding, end of year	53,541	53,382	51,192	44,672	44,499
Earnings (Loss) Per Share of Common Stock (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$3.92	$2.83	$3.12	$2.98	$2.57
Discontinued operations [b]	(0.32)	(1.23)	(3.83)	(0.04)	0.09 [e]
Non-controlling interest	(0.27)	(0.19)	—	—	—
Total	$3.33	$1.41	$(0.71)	$2.94	$2.66
Diluted earnings (loss) per average share -					
Continuing operations	$3.78	$2.75	$3.12	$2.97	$2.55
Discontinued operations [b]	(0.31)	(1.20)	(3.83)	(0.04)	0.09
Non-controlling interest	(0.26)	(0.18)	—	—	—
Total	$3.21	$1.37	$(0.71)	$2.93	$2.64
Dividends Declared per Share	$1.81	$1.68	$1.62	$1.56	$1.52
Book Value Per Share, End of Year	$31.92	$30.25	$28.63	$30.31	$28.84
Return on Average Equity [h]	11.7 %	8.9 %	10.0 %	10.0 %	9.1 %

SELECTED FINANCIAL DATA continued

Years ended December 31,	2017	2016	2015	2014	2013
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	941	941	841	841	790
Electric Utilities (purchased capacity)	110	110	210	210	150
Power Generation (owned generation)	269	269	269	269	309
Total generating capacity	1,320	1,320	1,320	1,320	1,249
Electric Utilities:					
MWh sold:					
Retail electric	5,189,084	5,140,519	4,990,594	4,775,808	4,642,254
Contracted wholesale	722,659	246,630	260,893	340,871	357,193
Wholesale off-system	661,263	769,843	1,000,085	1,118,641	1,456,762
Total MWh sold	6,573,006	6,156,992	6,251,572	6,235,320	6,456,209
Gas Utilities:					
Gas sold (Dth)	87,816,522	79,165,742	56,638,299	64,861,411	64,131,850
Transport volumes (Dth)	141,600,080	126,927,565	77,393,775	77,433,266	73,730,017
Power Generation Segment:					
MWh Sold (g)	1,589,428	1,868,513	1,796,242	1,760,160	1,564,789
MWh Purchased	69,377	85,993	68,744	38,237	5,481
Mining Segment:					
Tons of coal sold (thousands of tons)	4,183	3,817	4,140	4,317	4,285
Coal reserves (thousands of tons)	194,909	199,905	203,849	208,231	212,595

(a) The increase in 2016 includes the debt associated with the SourceGas acquisition (see Note 6 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(b) On November 1, 2017, we made the decision to divest our oil and gas business. 2017 includes an after-tax fair value impairment on held-for-sale assets of $13 million. 2016 includes non-cash after-tax impairment charges to crude oil and natural gas properties of $67 million. 2015 includes non-cash after-tax ceiling test impairment charges to crude oil and natural gas properties of $158 million and a non-cash after-tax equity investment impairment charge of $2.9 million (see Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(c) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Net income available for common stock for 2017 and 2016 was reduced by $14 million and $9.6 million, respectively, attributable to this noncontrolling interest. 2013 includes $6.6 million after-tax expense relating to the settlement of interest rate swaps and write-off of deferred financing costs in conjunction with the prepayment of Black Hills Wyoming's project financing.

(d) 2017, 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $2.8 million, $30 million and $6.7 million, respectively. 2016 and 2015 also include after-tax internal labor costs attributable to the SourceGas Acquisition of $9.1 million and $3.0 million that otherwise would have been charged to other segments. 2013 includes $20 million non-cash after-tax unrealized mark-to-market gains, respectively, related to certain interest rate swaps; 2013 also includes $7.6 million after-tax expense for a make-whole premium, write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt.

(e) Discontinued operations in 2013 includes post-closing adjustments and operations relating to Enserco, sold in 2012.

(f) In 2016, we issued 1.97 million shares at an average share price of $60.95 under our ATM equity offering program. In November 2015, we issued 6.3 million shares of common stock, par value $1.00 per share at a price of $40.25.

(g) The decrease in 2017 is driven by the joint dispatch agreement Colorado Electric became a part of in 2017. See details of this agreement in Item 1. Business and Properties, Electric Utilities Segment in this Annual Report on Form 10-K.

(h) Calculated based on Income (loss) from continuing operations available for common stock.

For additional information on our business segments see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note 5 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEMS 7 & MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS and 7A. OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a customer-focused, growth-oriented, vertically-integrated utility company operating in the United States. We report our operations and results in the following financial segments.

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 210,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska subsidiaries. Our Gas Utilities transport and distribute natural gas through our network to approximately 1,042,000 natural gas customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as available basis.

Our Gas Utilities also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 52,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air conditioning, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 63,000 and 31,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

Power Generation: Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts.

Mining: Our Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities.

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States. All of our non-utility business segments support our utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Overview: Our customer focus provides opportunities to expand our business by constructing additional rate base assets to serve our utility customers and expanding our non-regulated energy products and services to our wholesale customers.

Our Objective

Our objective is to be best-in-class relative to certain operational performance metrics, such as safety, power plant availability, electric and gas system reliability, efficiency, customer service and cost management. Our notable operational performance metrics for 2017 include:

- Our three electric utilities achieved 1st quartile reliability ranking with 67 customer minutes of outage time (SAIDI) in 2017 compared to industry averages (IEEE 2017 1st quartile is less than 97 minutes);

- Our power generation fleet achieved a forced outage factor of 5.04% for coal-fired plants, 1.42% for natural gas-fired turbines, 0.74% for natural gas-combined cycle power blocks and 0.17% for diesel plants in 2017, compared to an industry average* of 3.10%, 3.38%, 2.24% and 1.03%, respectively (*NERC GADS 2016 Data);

- Our power generation fleet availability was 89.82% for coal-fired plants, 95.70% for natural gas-fired turbines, 95.93% for natural gas-combined cycle power blocks, 99.53% for diesel-fired plants, and 94.06% for wind generation in 2017 while the industry averages** were 86.37%, 90.88%, 94.11%, 93.61 and 96.0% respectively (** NERC GADS 2016 data used for coal, natural gas-gas turbines, natural gas-combined cycles, and diesel plants; NERC GADS does not keep wind at this time; accordingly, wind average obtained from wind generation articles by manufacturer(s));

- Our safety TCIR of 1.3 compares to an industry average of 2.1+ and our DART rate of 0.8 compares to an industry average of 1.2+ (+ Bureau of Labor Statistics (BLS)-all utilities of all sizes - most recent industry averages are 2016); and
- Our mine completed over five years with no MSHA reportable injuries and received an award from the State of Wyoming for eight years without a lost time incident. The mine also received the State Mine Inspector's Award for the fourth year in a row for operating as the safest small mine and received the Mine Safety and Health Administration's Certificate of Achievement for No Lost Time Incidents.

The electric utility industry is facing requirements to upgrade aging infrastructure, deploy smart grid technology and comply with new state and federal environmental regulations and renewable portfolio standards. Increased energy efficiency and smart grid technologies suppress demand in many areas of the United States. These competing considerations present challenges to energy companies' approach to balancing capital spending and obtaining satisfactory rate recovery on investments.

State regulatory commissions have lowered authorized returns and implemented other regulatory mechanisms for cost recovery due to the slow-growing economy and concerns that utility rate increases may further harm local economies. The average awarded return on equity for investor-owned utilities over the past year has been just under 10%. The average regulatory lag is less than 12 months, according to the Edison Electric Institute. Sustained low interest rates heavily influence the lower rates of return, along with actions by state commissions to moderate rate increases during a period of economic recovery.

In our gas and electric utilities' service territories, we will continue to work with regulators to ensure we meet our obligations to serve projected customer demand and to comply with environmental mandates by constructing the infrastructure necessary to provide safe, reliable energy. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery that provides fair economic returns on our utility investments.

According to the U.S. Energy Information Administration, approximately 30% of electricity generated in the United States is from coal-fired power plants. It will take significant time and expense before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation's electric supply for the foreseeable future. The regulatory climate in recent years, combined with the EPA's regulations, have limited construction of new conventional coal-fired power plants, but, if technologies such as carbon capture and sequestration become more proven and less expensive, they could provide for the long-term economic use of coal. We have investigated and will continue to investigate the possible deployment of these technologies at our mine site in Wyoming.

Key Elements of our Business Strategy

Efficiently plan, construct and operate utility systems that provide safe, reliable and affordable energy to our customers and competitive, sustained returns for our shareholders. The Company is an electric and natural gas utility serving approximately 1.25 million utility customers in more than 800 communities in eight Rocky Mountain and Midwestern states, with a service territory that spans nearly 1,600 miles, reaching from Cody, Wyoming to Blytheville, Arkansas. Our natural gas utility business owns and operates a 45,000-mile natural gas transmission and distribution pipeline system and our electric utility business owns and operates 941 megawatts of generation capacity and 8,800 miles of transmission and distribution lines. The company's primary growth strategy is to invest in these utility systems to ensure the continued delivery of safe, reliable and affordable energy for customers and competitive, sustained returns for our shareholders.

Maintain a safe and reliable gas distribution system. We rigorously comply with all applicable federal, state and local regulations and strive to consistently meet industry best practice standards. Preventing natural gas losses from our gas delivery systems is of the utmost importance to ensure public and employee safety and to protect the environment. We construct, maintain and update our gas delivery systems with state of the art materials and products and continuously monitor their integrity. System leaks are repaired as soon as possible while ensuring the safety of the public and our employees. We have removed all cast and wrought iron from our natural gas transmission and distribution systems and they contain very minimal quantities of bare steel pipelines. Many of our gas utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that provide for customer rate adjustments which reflect the cost incurred in repairing and replacing the gas delivery systems.

Efficiently plan, construct and operate rate base power generation facilities to serve our electric utilities. Our company began as a vertically-integrated electric utility. This business model remains a core strength and strategy today as we invest in and operate efficient power generation resources to cost-effectively supply electricity to our customers. We strive to provide power at reasonable rates to our customers and earn competitive returns for our investors.

Our power production strategy focuses on low-cost construction and operation of our generating facilities. Our low power production costs result from a variety of factors including low fuel costs, efficiency in converting fuel into energy, low per unit operation and maintenance costs, and high levels of power plant availability. We leverage our mine-mouth coal-fired generating capacity to eliminate fuel transportation costs that often represent the largest component of the delivered cost of coal for many other utilities. Additionally, we operate our plants with high levels of availability as compared to industry benchmarks.

Rate-based generation assets offer several advantages for customers and shareholders, including:

- When generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run; especially when compared to power otherwise purchased from the open market through wholesale contracts that are periodically re-priced to reflect current and varying market conditions;

- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;

- The lower risk profile of rate-based generation assets contributes to stronger credit ratings which, in turn, can benefit both consumers and investors by lowering the cost of capital; and

- Investors are provided a long-term, reasonable, stable return on their investment.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. The energy and utility industries face uncertainty and potential investment opportunities related to existing and potential legislation and regulation intended to reduce GHG emissions and increase the use of renewable and other alternative energy sources. To date, many states have enacted, and others are considering, mandatory renewable energy standards, requiring utilities to meet certain thresholds of renewable energy generation. Some states have either enacted or are considering legislation setting GHG emissions reduction targets. Federal legislation for both renewable energy standards and GHG emission reductions has been considered and may be implemented in the future. Mandates for the use of renewable energy or the reduction of GHG emissions will likely provide investment opportunities for our electric utilities, gas utilities and power generation business. These mandates will also likely increase prices for electricity and/or natural gas for our utility customers. As a regulated utility we are responsible for providing safe, reliable and affordable sources of energy to our customers. Accordingly, we employ a customer-centered strategy for complying with renewable energy standards and GHG emission regulations that balance our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.
Build and maintain strong relationships with wholesale power customers of our utilities and our power generation business. We strive to build strong relationships with other utilities, municipalities and wholesale customers. We believe we will continue to be a primary provider of electricity to wholesale utility customers, who will continue to need products such as capacity and energy to reliably serve their customers. By providing these products under long-term contracts, we help our customers meet their energy needs. We also earn more stable revenues and greater returns for shareholders over the long term than we would by selling energy into more volatile energy spot markets. In addition, relationships that we have established with wholesale power customers have developed into other opportunities. MEAN, MDU and the City of Gillette, Wyoming were wholesale power customers that are now joint owners in two of our power plants, Wygen I and Wygen III, reducing risk and providing steady revenues.

Vertically integrate businesses that are supportive of our electric and natural gas utility businesses. While our primary focus is on growing our core utilities, we selectively invest in vertically integrated businesses that provide cost effective and efficient fuel and energy to our utilities. We currently own and operate a coal mine and power generation assets that are vertically integrated into and supportive of our electric utilities. These operations are located at our utility generating complexes and are physically integrated into our electric utility operations.

Our surface coal mine is located immediately adjacent to our Gillette energy complex in northeastern Wyoming, where all five of our coal-fired power plants are located. We operate and own 100% or own a majority interest in four of the five plants; we have a 20% interest in the fifth plant, which is operated by a third party. The coal mine provides low-sulfur coal directly to these power plants via a conveyor belt system, minimizing coal transportation costs. On average, the coal can be delivered to the adjacent power plants at substantially less than $1.00 per MMBtu, providing very cost competitive fuel to our power plants when compared to other coal-fired and gas-fired power plants.

We have a power generation segment that employs professionals with significant expertise in planning and building power generation facilities, having constructed 19 coal-fired, gas-fired and renewable generation projects since 1995 with aggregate project costs in excess of $2 billion. This group also provides shared services to our electric utilities' generation facilities, resulting in efficient management of all of the company's generation assets. In certain states, our electric utilities are required to competitively bid for generation resources needed to serve customers. Generally, our power generation segment submits bids in response to those competitive solicitations. Our generation segment can often realize competitive advantages provided by prior construction expertise, fuel supply advantages and by co-locating new plants at existing sites, reducing infrastructure and operating costs.

Expand utility operations through selective acquisitions of electric and gas utilities. The electric and natural gas utility industries have consolidated significantly over the past decade and continue to consolidate. We have successfully acquired and integrated numerous utility systems since 2005, including two large, transformational acquisitions - the Aquila utility properties in 2008 and SourceGas in 2016. Through these acquisitions, we developed a scalable platform that simplifies the rapid integration of acquired utilities, providing significant benefits to both customers and shareholders. The company targets small to large utilities, including municipal and private utility systems, located primarily in geographies that are near to or contiguous with our existing utility service territories and provide long-term value for both customers and shareholders. In the near-term, we do not expect to pursue large utility acquisitions, particularly given the high valuation multiples realized in recent utility transactions. We will continue to pursue the purchase of small utility systems within or near our geographic footprint, which can be quickly and efficiently integrated into our existing utilities.

Grow our dividend. We are extremely proud of our track record for annual dividend increases for shareholders. In January 2018, we declared a dividend of $0.475 per share, equivalent to an annual dividend rate of $1.90 per share. This annual equivalent rate represents an increase of 5% over the total 2017 dividend of $1.81 per share and the 48th consecutive annual dividend increase. We intend to continue our record of annual dividend increases with a targeted dividend payout ratio of 50% to 60%. This target payout ratio provides the flexibility for greater increases to our dividend during periods of relatively slow earnings growth.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent and earnings accretive business growth. We have demonstrated our ability to cost-effectively access the debt and equity markets, while maintaining our investment-grade issuer credit rating.

Prospective Information

We expect to generate long-term growth through the expansion of integrated utilities and supporting operations. Sustained growth requires continued capital deployment. Our integrated energy portfolio, focused primarily on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from capital deployment opportunities at our utilities and continued focus on improving efficiencies and reducing costs. Although dependent on market conditions, we are confident in our ability to obtain additional financing, as necessary, to continue our growth plans. We remain focused on prudently managing our operations and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

Electric Utilities

In September 2017, the Mountain West Transmission Group, which includes all of Black Hills electric utilities and seven other electricity providers, formally expressed an interest in joining the Southwest Power Pool (SPP) regional transmission organization. If membership is deemed beneficial, filings with FERC and state public utility commissions would likely occur in mid-2018 with integration into SPP in late 2019.

On January 17, 2017, Colorado Electric received approval from the CPUC on a settlement agreement for its electric resource plan which provides for the addition of 60 megawatts of renewable energy to be in service by 2019. The resource plan was filed on June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to acquire renewable energy resources to comply with the Colorado Renewable

Energy Standard and presented the results to the CPUC on February 9, 2018. We expect a final decision from the CPUC in the second quarter of 2018 approving, conditioning, modifying or rejecting Colorado Electric’s recommended portfolio.

Retail MWhs sold increased in 2017 primarily due to industrial load growth at Wyoming Electric, which set a new all-time summer peak load of 249 MW in July 2017.

Construction was completed on the 144 mile transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

Gas Utilities

In 2017, we filed requests for rate reviews in Arkansas, Wyoming and Colorado, driven by investments made on recently acquired utilities to replace, upgrade and maintain natural gas transmission and distribution pipelines. See 2017 Results of Operations and Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

Our Gas Utilities invested in our gas distribution network and related technology such as advanced metering infrastructure and mobile data terminals. We continually monitor our investments and costs of operations in all states to determine the appropriateness of additional rate reviews or other rate filings. As part of our growth strategy, we continue to look for opportunities to purchase municipal and privately-owned gas infrastructure and distribution systems within or nearby our service territories.

Mining

Production from the Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production was approximately 4.2 million tons for 2017. Mining operations moved to an area with higher overburden ratios in 2017, which increased mining costs. However, lower fuel costs and efficiencies in executing our mine plan partially offset these costs. Our stripping ratio at December 31, 2017 was 2.16 and we expect stripping ratios in 2018 to be approximately 2.15 as the areas planned for mining contain comparable overburden.

Our strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Approximately one-half of our coal is sold under cost-plus contracts with affiliates. Historically our limited off-site sales have been to consumers within a close proximity to our mine, including off-site sales contracts served by truck. We continue to pursue new opportunities to market our coal despite limitations inherent to transporting our lower-heat content coal.

Corporate and Other

We utilized favorable short-term borrowings from our CP program to pay down $100 million on a Corporate term loan due in 2019 with principal payments of $50 million paid in May and an additional $50 million paid in July. In August 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. See additional detail in the 2017 Corporate highlights.

Results of Operations

Executive Summary and Overview

	For the Years Ended December 31,				
	2017	Variance	2016	Variance	2015
	(in thousands)				
Revenue					
Revenue	$1,810,447	$143,412	$1,667,035	$280,036	$1,386,999
Intercompany eliminations	(130,181)	(2,062)	(128,119)	(2,442)	(125,677)
	$1,680,266	$141,350	$1,538,916	$277,594	$1,261,322
Income from continuing operations available for common stock [a]					
Electric Utilities	$110,082	$24,255	$85,827	$8,248	$77,579
Gas Utilities [b]	65,795	6,171	59,624	20,318	39,306
Power Generation [c]	46,479	20,549	25,930	(6,720)	32,650
Mining	14,386	4,333	10,053	(1,817)	11,870
	236,742	55,308	181,434	20,029	161,405
Corporate and Other [a] [b] [d] [e]	(42,609)	1,693	(44,302)	(24,445)	(19,857)
Income from continuing operations	194,133	57,001	137,132	(4,416)	141,548
(Loss) from discontinued operations, net of tax [f] [g]	(17,099)	47,063	(64,162)	109,497	(173,659)
Net income (loss) available for common stock	$177,034	$104,064	$72,970	$105,081	$(32,111)

(a) Income from continuing operations available for common stock for 2017 includes a net tax benefit of $7.6 million from the revaluation of deferred tax balances due to a decrease in the statutory Federal income tax rate resulting from the TCJA. This benefit's impact to our operating segments and Corporate and Other was: Electric Utilities - $23 million tax benefit; Gas Utilities - $6.8 million tax expense; Power Generation - $24 million tax benefit; Mining - $2.7 million tax benefit; Corporate and Other - $35 million tax expense which includes $28 million of tax expense from the revaluation of Corporate deferred taxes, as well as an additional $7.0 million of tax expense from the revaluation of deferred taxes that were originally recorded to AOCI.

(b) Income from continuing operations available for common stock for 2017 includes a $4.1 million tax benefit from a true-up to the filed 2016 SourceGas tax returns relating to the SourceGas Acquisition.

(c) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Income from continuing operations available for common stock for 2017 and 2016 was reduced by $14 million and $9.6 million, respectively, attributable to this noncontrolling interest.

(d) Income from continuing operations available for common stock for 2017, 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $2.8 million, $30 million and $6.7 million, respectively and after-tax internal labor costs attributable to the SourceGas Acquisition of $0.5 million, $9.1 million and $3.0 million, respectively that otherwise would have been charged to other business segments.

(e) Income from continuing operations available for common stock for 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(f) Loss from discontinued operations in 2017, 2016 and 2015 included non-cash after-tax impairments of crude oil and natural gas properties of $13 million, $67 million and $160 million, respectively. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(g) Loss from discontinued operations in 2016 included a tax benefit of approximately $5.8 million recognized from additional percentage depletion deductions that are being claimed with respect to our oil and gas properties involving prior years.

The following business group and segment information does not include intercompany eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Per share information references diluted shares unless otherwise noted.

2017 Compared to 2016

Income from continuing operations available for common stock was $194 million, or $3.52 per diluted share in 2017 compared to $137 million, or $2.57 per diluted share in 2016. The variance to the prior year was primarily due to:

- Corporate and Other, excluding tax reform impacts, decreased by approximately $37 million compared to the same period in the prior year driven primarily by a $27 million reduction of after-tax external acquisition and transition costs, a reduction of approximately $8.6 million of internal labor attributed to the SourceGas Acquisition and lower reallocated discontinued operation expenses of approximately $2.9 million, partially offset by a $4.4 million tax benefit in 2016;
- Gas Utilities' earnings, excluding tax reform impacts, increased approximately $13 million, with a full year of earnings from our acquired SourceGas utilities compared to approximately 10.5 months in 2016, and a $4.1 million tax benefit recognized in 2017;
- We recorded a net tax benefit of approximately $8 million as a result of the revaluation of deferred tax balances due to the decrease in the statutory Federal income tax rate as a result of the TCJA. This benefit's impact to our operating segments and Corporate and Other was:
Electric Utilities - $23 million tax benefit
Gas Utilities - $6.8 million tax expense
Power Generation - $24 million tax benefit
Mining - $2.7 million tax benefit
Corporate and Other - $35 million tax expense consisting of $28 million of tax expense from the revaluation of Corporate deferred tax balances and $7 million of tax expense from the revaluation of deferred taxes that were originally recorded to AOCI.
- Electric Utilities' earnings, excluding tax reform impacts, were comparable to the prior year reflecting an increase from returns on prior year generation investments, offset by higher employee costs and higher generation maintenance expenses;
- Earnings at our Power Generation segment, excluding tax reform impacts, decreased $3.5 million primarily due to an increase in net income attributable to noncontrolling interests, reflecting a full year in 2017 compared to approximately 8.5 months in 2016; and
- Earnings at our Mining segment, excluding tax reform impacts, increased approximately $1.6 million due to an increase in tons sold as a result of an extended outage in the prior year;.

Net income (loss) available for common stock was $177 million, or $3.21 per diluted share in 2017, compared to $73 million, or $1.37 per share in 2016. BHEP has been reclassified and is included in discontinued operations. (Loss) from discontinued operations was $(17) million or $(0.31) per diluted share in 2017 compared to $(64) million or $(1.20) per diluted share in 2016. Discontinued operations in 2017 included an after-tax fair value impairment of assets of approximately $13 million compared to 2016 which included non-cash after-tax oil and gas property impairment charges of $67 million. Also included in 2016 discontinued operations was a $5.8 million tax benefit recognized from additional percentage depletion deductions that were claimed with respect to our oil and gas properties involving prior years.

2017 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, winter weather was mostly comparable to the prior year and the summer was milder in 2017 compared to the prior year. Heating degree days in 2017 were 11% lower than normal compared to 13% lower than normal in 2016. Cooling degree days for the full year of 2017 were 14% higher than normal compared to 26% higher than normal in 2016.

On January 17, 2017, Colorado Electric received approval from the CPUC on a settlement agreement for its electric resource plan which provides for the addition of 60 megawatts of renewable energy to be in service by 2019. The resource plan was filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to acquire renewable energy resources to comply with the Colorado Renewable Energy Standard and presented the results to the CPUC on February 9, 2018. We expect a final decision from the CPUC in the second quarter of 2018 approving, conditioning, modifying or rejecting Colorado Electric's recommended portfolio.

- On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision to increase annual revenue by $1.2 million. This application was denied by the CPUC on June 9, 2017. We subsequently filed an appeal of this decision with Denver County District Court on July 10, 2017. On October 4, 2017, the Company filed an Opening Brief. The Company filed a Reply Brief on November 22, 2017. The matter is pending.

- Construction was completed on the 144 mile transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

- On July 19, 2017, Wyoming Electric set a new summer load peak of 249 MW, exceeding the previous summer peak of 236 MW set in July 2016.

Gas Utilities

- Our service territories reported comparable year-over-year winter weather as measured by heating degree days compared to the 30-year average. Combined heating degree days for the full year in 2017 were 10% less than normal compared to 11% less than normal in the same period in 2016.

The Gas Utilities also experienced cooler summer temperatures and higher precipitation levels during the third quarter of 2017 compared to the same period in 2016, which reduced the irrigation load delivered to agricultural customers, primarily in our Nebraska service territory.

- On December 15, 2017, Arkansas Gas filed a rate review application with the APSC requesting an annual increase in revenue of approximately $30 million. The annual increase is based on a return on equity of 10.2% and a capital structure of 45.3% debt and 54.7% equity. This rate review was driven by approximately $160 million of investments made since 2016 to replace, upgrade and maintain Arkansas Gas' approximately 5,500 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in the fourth quarter of 2018. We are reviewing the impact of tax reform as it applies to the filing.

- On November 17, 2017, Wyoming Gas requested rate review application with the WPSC requesting an annual increase in revenue of approximately $1.4 million for natural gas system improvements supporting its Northwest Wyoming customers. The annual increase is based on a return on equity of 10.2% and a capital structure of 46% debt and 54% equity. This rate review was driven by approximately $6 million of investments made since 2015 to replace, upgrade and maintain approximately 620 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in mid-2018. We are reviewing the impact of tax reform as it applies to the filing.

- On October 3, 2017, RMNG filed a rate review application with the CPUC requesting an annual increase in revenue of $2.2 million and an extension of SSIR to recover costs from 2018 through 2022. The annual increase is based on a return on equity of 12.25% and a capital structure of 53.37% debt and 46.63% equity. This rate review was driven by the impending expiration of the SSIR on May 31, 2018; this application requests a continuation of the SSIR through 2022. We are reviewing the impact of tax reform as it applies to the filing.

Corporate Activities

- On August 4, 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior year program other than the aggregate value increased from $200 million to $300 million. We did not issue any common shares during the twelve months ended December 31, 2017.

- On December 12, 2017, Moody's affirmed Black Hills' credit rating at Baa2 with a Stable outlook.
- On October 4, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and maintained a Stable outlook.
- On July 21, 2017, S&P affirmed Black Hills' credit rating at BBB rating and maintained a Stable outlook.

Discontinued Operations

- On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90 percent of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets with minimal value left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018. The results of our Oil and Gas segment are reflected in discontinued operations, other than certain general and administrative and interest costs which have been reallocated to our other segments. Oil and Gas segment assets and liabilities are classified as held for sale.

2016 Compared to 2015

Income from continuing operations available for common stock was $137 million, or $2.57 per diluted share in 2016, compared to $142 million, or $3.12 per diluted share in 2015. The variance to the prior year was primarily due to:

- higher earnings at our Electric Utilities of $8.2 million driven primarily by returns on generation investments;
- higher earnings at our Gas Utilities of approximately $20 million, which include earnings of $15 million from our acquired SourceGas utilities since the acquisition date of February 12, 2016;
- tax benefits of approximately $5.1 million from the re-measurement of uncertain tax positions' liability predicated on an agreement reached with IRS Appeals;
- Increased corporate expenses which included approximately $30 million of after-tax incremental acquisition and transition costs related to SourceGas;
- Lower earnings at our Power Generation segment due to net income attributable to noncontrolling interests of $9.6 million;
- Lower earnings at our Mining segment due to an extended 2016 outage at the Wyodak plant.

Net income (loss) available for common stock was $73 million, or $1.37 per diluted share in 2016, compared to $(32) million or $(0.71) per diluted share in 2015. BHEP has been reclassified and is included in discontinued operations. (Loss) from discontinued operations was $(64) million or $(1.20) per diluted share in 2016 compared to $(174) million or $(3.83) per diluted share. Discontinued operations in 2016 included non-cash after-tax oil and gas property impairment charges of $67 million compared to non-cash after-tax ceiling test impairments of our oil and gas properties of $158 million in 2015.

2016 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, mild winter weather in 2016 partially offset a hotter than normal summer. Heating degree days were 2% lower than the prior year and 13% lower than normal. Offsetting this decrease was weather related demand during the peak summer months. Cooling degree days for the full year of 2016 were 9% higher than the same period in the prior year and 26% higher than normal.

- On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.

Construction riders related to the project increased gross margins by approximately $5.1 million for the year ended December 31, 2016.

- On November 8, 2016, Colorado Electric completed the purchase of Peak View, a $109 million, 60 MW Wind Project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased through progress payments throughout 2016 under a commission approved third-party build- transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. The Commission’s settlement agreement provides for recovery of the costs of the project through Colorado Electric’s Electric Cost Adjustments, Renewable Energy Standard Surcharge and Transmission Cost Adjustment for 10 years, after which Colorado Electric can propose base rate recovery.

- During the first quarter of 2016, South Dakota Electric commenced construction of the $54 million, 230-kV, 144 mile-long transmission line that connects the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. Recovery is concurrent through the FERC transmission tariff. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service in May of 2017.

Gas Utilities

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing. See additional information below under Corporate activities.

- Gas Utilities were unfavorably impacted by milder weather in 2016 compared to 2015. Our service territories reported warmer than normal winter weather as measured by heating degree days, compared to the 30-year average, and compared to 2015. Heating degree days for the full year in 2016 were 11% less than normal and 1% less than the same period in 2015.

Power Generation

- Black Hills Colorado IPP owns and operates a 200 MW, combined cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. FERC approval of the sale was received on March 29, 2016. Proceeds from the sale were used to pay down short-term debt. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric.

Corporate Activities

- In 2016, we implemented a $750 million, unsecured CP Program that is backstopped by our Revolving Credit Facility, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 and we entered into a new $500 million term loan expiring August 9, 2019. We completed the permanent financing for the SourceGas Acquisition. In addition to the net proceeds of $536 million from our November 2015 equity issuances, we completed the Acquisition financing with $546 million of net proceeds from our January 2016 debt offering. We also refinanced the long-term debt assumed with the SourceGas Acquisition primarily through $693 million of net proceeds from our August 19, 2016 debt offerings. In addition to our debt refinancings, we issued 1.97 million shares of common stock for approximately $119 million through our ATM equity offering program, and sold a 49.9% noncontrolling interest in Black Hills Colorado IPP for $216 million. On June 7, 2016, we issued a $29 million, declining balance five-year term loan maturing June 7, 2021, to finance the early termination of a gas supply agreement. See Footnotes 6 and 7 of the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K for additional information relating to our long-term debt and notes payable.

- On December 9, 2016, Moody's issued a Baa2 rating with a Stable outlook, which reflects the higher debt leverage resulting from the incremental debt used to fund the SourceGas Acquisition.

- During the first quarter of 2016, we reached an agreement in principle with IRS Appeals with respect to our liability for unrecognized tax benefits attributable to the like-kind exchange effectuated in connection with the 2008 IPP Transaction and the 2008 Aquila Transaction. This agreement resulted in a tax benefit of approximately $5.1 million in the first quarter of 2016. See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional details on this agreement.

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing.

- On February 12, 2016, S&P affirmed the BHC credit rating of BBB and maintained a stable outlook after our acquisition of SourceGas, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.

- On February 12, 2016, Fitch affirmed the BHC credit rating of BBB+ and maintained a negative outlook after our acquisition of SourceGas, which reflects the initial increased leverage associated with the SourceGas Acquisition.

- On January 20, 2016, we executed a 10-year, $150 million notional, forward starting pay fixed interest rate swap at an all-in interest rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29%, to hedge the risks of interest rate movement between the hedge dates and pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled and terminated these interest rate swaps for a loss of $29 million. The loss recorded in AOCI is being amortized over the 10-year life of the associated debt.

Operating Results

A discussion of operating results from our business segments follows.

All amounts are presented on a pre-tax basis unless otherwise indicated.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors’ understanding of our operating performance.

In our Management Discussion and Analysis of Results of Operations, gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel, purchased power and cost of gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies’ gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$704,650	$27,369	$677,281	$(2,562)	$679,843
Total fuel and purchased power	268,405	7,056	261,349	(8,060)	269,409
Gross margin	436,245	20,313	415,932	5,498	410,434
Operations and maintenance	172,307	14,173	158,134	(2,790)	160,924
Depreciation and amortization	93,315	8,670	84,645	3,716	80,929
Total operating expenses	265,622	22,843	242,779	926	241,853
Operating income	170,623	(2,530)	173,153	4,572	168,581
Interest expense, net	(52,274)	(1,983)	(50,291)	754	(51,045)
Other income (expense), net	1,730	(1,463)	3,193	1,977	1,216
Income tax expense	(9,997)	30,231	(40,228)	945	(41,173)
Net income (loss) available for common stock	$110,082	$24,255	$85,827	$8,248	$77,579

	2017	2016	2015
Regulated power plant fleet availability:			
Coal-fired plants [(a) (b) (c)]	88.9%	90.2%	91.5%
Natural gas fired plants and Other plants	96.1%	95.1%	95.4%
Wind [(d)]	93.3%	79.3%	99.3%
Total availability	93.6%	93.5%	94.0%
Wind capacity factor	36.7%	36.6%	32.4%

(a) 2017 reflects planned outages at Neil Simpson II, Wyodak, and Wygen II.

(b) 2016 reflects a planned outage at Wygen III, an extended planned outage at Wyodak and an unplanned outage at Neil Simpson II.

(c) 2015 reflects planned outages at Neil Simpson II, Wygen II and Wygen III.

(d) 2017 and 2016 were lower due to the addition of Peak View Wind Project with ownership transfer in November, 2016.

2017 Compared to 2016

Gross margin increased over the prior year primarily reflecting a $7.8 million return on investment from the Peak View Wind Project, a $7.4 million increase in rider revenues primarily related to transmission investment recovery, and a $2.1 million increase in commercial and industrial margins driven by increased demand largely associated with data centers in Cheyenne, Wyoming. A variety of smaller items contribute to the remainder of the net increase.

Operations and maintenance increased primarily due to $4.8 million of higher employee costs as a result of prior year integration activities and transition expenses charged to Corporate and Other, $2.6 million of higher generation outage expenses, $1.9 million of higher property taxes with an increased asset base, and $1.7 million of higher operating expenses from the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station. An additional $1.3 million of indirect corporate costs are included at the electric utilities; these costs were previously charged to our Oil and Gas segment, now reported as discontinued operations.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to the prior year.

Other (expense) income, net decreased due to reduced AFUDC with lower capital spend.

Income tax benefit (expense): The effective tax rate was lower in 2017 primarily due to a $23 million benefit resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017. This benefit was primarily related to the revaluation of net operating losses and other tax basis items not included in the ratemaking construct. Production tax credits associated with the Peak View Wind Project increased by $4.0 million reflecting a full year of production tax credits compared to two months in 2016. The prior year included a $1.3 million benefit related to the flow-through treatment of a treasury grant related to the Busch Ranch Wind Project.

2016 Compared to 2015

Gross margin increased over the prior year reflecting increased rider margins of $4.9 million driven primarily by our construction and TCA riders, an increase of $2.4 million in commercial and industrial margins driven by increased demand, a $1.5 million return on investment from the Peak View Wind Project, and a $1.4 million increase in residential margins driven by favorable weather. Offsetting these increases was a $2.1 million prior-year benefit as a result of a one-time settlement with the Colorado Public Utilities Commission on our renewable energy standard adjustment related to the Busch Ranch wind farm, a prior-year increase in return on invested capital of $1.2 million from South Dakota Electric’s rate case, and a $1.3 million decrease due to third-party billing true-ups relating to the current and prior years.

Operations and maintenance decreased primarily as a result of approximately $5.8 million lower employee costs primarily driven by a change in expense allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities. This decrease is partially offset by higher operating costs from the Peak View Wind Project, which commenced commercial operation in November 2016, and increased vegetation management costs.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of Peak View Wind Project.

Interest expense, net decreased primarily due to higher AFUDC interest income driven by construction in process as compared to prior year.

Other (expense) income, net increased primarily due to higher AFUDC equity in the current period compared to prior year.

Income tax benefit (expense): The effective tax rate was lower than prior year primarily due to the accelerated recognition of benefits associated with certain tax incentives.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue:					
Natural gas - regulated	$865,831	$96,749	$769,082	$249,084	$519,998
Other - non-regulated	81,799	12,538	69,261	37,959	31,302
Total revenue	947,630	109,287	838,343	287,043	551,300
Cost of natural gas sold:					
Natural gas - regulated	381,259	65,641	315,618	31,985	283,633
Other - non-regulated	28,344	(8,203)	36,547	20,535	16,012
Total cost of natural gas sold	409,603	57,438	352,165	52,520	299,645
Gross margin:					
Natural gas - regulated	484,572	31,108	453,464	217,099	236,365
Other - non-regulated	53,455	20,741	32,714	17,424	15,290
Total gross margin	538,027	51,849	486,178	234,523	251,655
Operations and maintenance	269,190	23,364	245,826	105,103	140,723
Depreciation and amortization	83,732	5,397	78,335	46,009	32,326
Total operating expenses	352,922	28,761	324,161	151,112	173,049
Operating income	185,105	23,088	162,017	83,411	78,606
Interest expense, net	(78,575)	(3,562)	(75,013)	(57,702)	(17,311)
Other income (expense), net	(829)	(1,013)	184	(131)	315
Income tax expense	(39,799)	(12,337)	(27,462)	(5,158)	(22,304)
Net income (loss)	65,902	6,176	59,726	20,420	39,306
Net income attributable to noncontrolling interest	(107)	(5)	(102)	(102)	—
Net income (loss) available for common stock	$65,795	$6,171	$59,624	$20,318	$39,306

2017 Compared to 2016

Gross margin increased primarily due to additional margins of approximately $51 million contributed by the SourceGas utilities in the first quarter of 2017 compared to the first quarter of 2016 which included approximately 1.5 months of SourceGas results. 2017 reflects a full twelve months of SourceGas results as compared to approximately 10.5 months in 2016.

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities, reflecting a full twelve months of results in 2017 as compared to approximately 10.5 months in 2016. Employee-related expenses increased $6.2 million for the Black Hills legacy gas utilities as a result of prior year integration activities and transition expenses charged to Corporate and Other. An additional $1.6 million of indirect corporate costs are included at the gas utilities; these costs were previously charged to our Oil and Gas segment, now reported as discontinued operations. A variety of smaller items contribute to the partially offsetting decrease in operations and maintenance expenses.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities.

Interest expense, net increased primarily due to additional interest expense from the acquired SourceGas utilities.

Other (expense) income, net was comparable to the same period in the prior year.

Income tax: The effective tax rate increased in 2017 primarily due to additional tax expense of $6.8 million as a result of the TCJA enacted on December 22, 2017 and from a $2.2 million tax benefit recognized in the prior year primarily related to favorable flow-through adjustments recognized in accordance with prescribed regulatory treatment. Partially offsetting these is a $4.1 million tax benefit recognized in the current year from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

2016 Compared to 2015

Gross margin increased primarily due to margins of approximately $236 million contributed by the SourceGas utilities acquired on Feb. 12, 2016 and Energy West Wyoming utility acquired on July 1, 2015. Partially offsetting this increase is a $2.0 million decrease due to weather. Heating degree days were 1% lower than the prior year and 11% lower than normal.

Operations and maintenance increased primarily due to additional operating costs of approximately $111 million for the acquired SourceGas utilities and Energy West Wyoming utility. Partially offsetting this increase were approximately $7.4 million lower employee costs primarily driven by a change in expense allocations impacting the gas utilities as a result of integrating the acquired SourceGas utilities.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas and Energy West Wyoming utilities of approximately $45 million, and due to a higher asset base at our other gas utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $58 million from the debt associated with the acquired SourceGas utilities.

Income tax: The effective tax rate for 2016, including the impact of the acquired SourceGas and Energy West Wyoming utilities, reflects additional tax benefits related primarily to a favorable flow through adjustment. Such adjustments are related to certain tax benefits that are recognized currently in accordance with prescribed regulatory treatment.

Power Generation

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$91,546	$415	$91,131	$ 341	$90,790
Operations and maintenance	32,382	(254)	32,636	496	32,140
Depreciation and amortization	5,993	1,889	4,104	(225)	4,329
Total operating expenses	38,375	1,635	36,740	271	36,469
Operating income	53,171	(1,220)	54,391	70	54,321
Interest expense, net	(2,836)	(1,061)	(1,775)	1,428	(3,203)
Other income (expense), net	(54)	(56)	2	(69)	71
Income tax benefit (expense)	10,333	27,462	(17,129)	1,410	(18,539)
Net income (loss)	60,614	25,125	35,489	2,839	32,650
Net income attributable to noncontrolling interest	(14,135)	(4,576)	(9,559)	(9,559)	—
Net income (loss) available for common stock	$46,479	$20,549	$25,930	(6,720)	$32,650

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Net income available for common stock for the year ended December 31, 2017 was reduced by $14 million, and reduced by $9.6 million for the year ended December 31, 2016. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

	2017	2016	2015
Contracted fleet plant availability:			
Gas-fired plants	99.2%	99.2%	99.1%
Coal-fired plants [(a)]	96.9%	95.5%	98.4%
Total	98.6%	98.3%	98.9%

(a) Wygen I experienced an unplanned outage in 2016 and a planned outage in 2017.

2017 Compared to 2016

Net income available for common stock for the Power Generation segment was $46 million for the year ended December 31, 2017, compared to Net income available for common stock of $26 million for the same period in 2016. Revenue and operating expenses were comparable to the same period in the prior year and depreciation expense increased on non-leased assets. The variance to the prior year was primarily driven by a $24 million current year tax benefit recognized from the revaluation of deferred tax liabilities in accordance with the TCJA enacted on December 22, 2017.

2016 Compared to 2015

Net income available for common stock for the Power Generation segment was $26 million for the year ended December 31, 2016, compared to Net income available for common stock of $33 million for the same period in 2015.

The variance to the prior year was primarily attributable to the increase in noncontrolling interest of $9.6 million as a result of the noncontrolling interest sale in April 2016.

Mining

Mining operating results for the years ended December 31 were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$66,621	$6,341	$60,280	$(4,786)	$65,066
Operations and maintenance	44,882	5,306	39,576	(2,054)	41,630
Depreciation, depletion and amortization	8,239	(1,107)	9,346	(460)	9,806
Total operating expenses	53,121	4,199	48,922	(2,514)	51,436
Operating income (loss)	13,500	2,142	11,358	(2,272)	13,630
Interest (expense) income, net	(205)	172	(377)	22	(399)
Other income, net	2,191	(18)	2,209	(38)	2,247
Income tax benefit (expense)	(1,100)	2,037	(3,137)	471	(3,608)
Net income (loss) available for common stock	$14,386	$4,333	$10,053	$(1,817)	$11,870

The following table provides certain operating statistics for the Mining segment (in thousands):

	2017	2016	2015
Tons of coal sold	4,183	3,817	4,140
Cubic yards of overburden moved [(a)]	9,018	7,916	6,088
Coal reserves at year-end	194,909	199,905	203,849

(a) Increase in overburden was due to relocating mining operations to areas of the mine with higher overburden.

2017 Compared to 2016

Revenue increased primarily due to a 10 percent increase in tons sold driven primarily by an 11-week outage at the Wyodak plant in the prior year.

Operations and maintenance increased due to higher equipment major maintenance, higher overburden moved and higher royalties and production taxes on increased revenues.

Depreciation, depletion and amortization decreased primarily due to lower plant in service and lower asset retirement obligation costs.

Interest (expense) income, net was comparable to the same period in the prior year.

Income tax: The effective tax rate is lower in 2017 primarily due to a $2.7 million benefit resulting from revaluation of net deferred tax liabilities in accordance with the enactment of the TCJA on December 22, 2017.

2016 Compared to 2015

Revenue decreased primarily due to an 8 percent decrease in tons sold resulting from a planned five-week outage in the second quarter of 2016, which was extended by an additional six weeks at Wyodak plant due to an unplanned major repair of a turbine rotor. Pricing was comparable to the same period in the prior year. Approximately 50 percent of our coal production was sold under contracts that are priced based on actual mining costs, including income taxes, as compared to 46 percent for the same period in the prior year.

Operations and maintenance decreased due to lower major maintenance requirements, fuel costs, and employee costs, as well as decreased royalties and revenue-related taxes driven by decreased revenue compared to the same period in the prior year.

Depreciation, depletion and amortization decreased primarily due to revised cost estimates for our asset retirement obligation driving lower accretion and depreciation.

Interest (expense) income, net is comparable to the same period in the prior year.

Income tax: The effective tax rate was comparable to the same period in the prior year.

Corporate and Other

Corporate and Other represents certain unallocated expenses for corporate and other administrative activities and interest and taxes that support our reportable operating segments. Below is a summary of operating expenses and tax (expenses) benefits included in Corporate and Other for the years ended December 31:

(in thousands)	2017	Variance	2016	Variance	2015
Tax Reform Impact [a]	$(28,402)	$(28,402)	$—	$—	$—
Tax Reform Impact - AOCI [a]	(7,000)	(7,000)	—	—	—
External acquisition costs, after-tax [b]	(2,489)	27,231	(29,720)	(23,020)	(6,700)
Internal acquisition labor, after-tax [b]	(500)	8,566	(9,066)	(6,066)	(3,000)
Discontinued operations operating expense reallocation [c]	(948)	2,540	(3,488)	764	(4,252)
Discontinued operations interest expense reallocation [c]	(3,215)	397	(3,612)	(1,369)	(2,243)
Tax benefit [d]	—	(4,400)	4,400	4,400	—
Other corporate expenses	(55)	2,761	(2,816)	846	(3,662)
Net (Loss) from Corporate and Other	$(42,609)	$1,693	$(44,302)	$(24,445)	$(19,857)

(a) Represents the revaluation of deferred tax balances not attributable to our operating segments or discontinued operations due to the decrease in the statutory Federal income tax rate as a result of the TCJA. Deferred taxes originally recorded to AOCI were also revalued to reflect the decrease in the statutory Federal income tax rate. See Notes 15 and 16 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more details.

(b) Acquisition and transition costs attributed to SourceGas acquisition including incremental transaction costs consisting of professional fees, financing fees, employee-related expenses and other miscellaneous costs and internal labor costs attributable to the acquisition that would otherwise have been charged to the other business segments.

(c) Reallocated indirect corporate operating costs and interest expenses previously allocated to BHEP which are not reclassified to discontinued operations in accordance with GAAP as they have a continuing impact on the Company. After-tax 2017 operating expenses of approximately $2.0 million were reallocated to our other business segments in 2017. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more details.

(d) We recognized a $4.4 million tax benefit during 2016 as a result of an agreement reached with IRS Appeals relating to the release of the reserve for after-tax interest expense previously accrued with respect to the liability for uncertain tax positions involving a like-kind exchange transaction from 2008.

2017 Compared to 2016

Net (loss) available for common stock for the twelve months ended December 31, 2017, was $(43) million compared to net (loss) available for common stock of $(44) million for the same period in the prior year. The variance from the prior year was due to:

- Tax expense of $35 million not attributable to our operating segments reflecting the revaluation of deferred tax balances, including those originally recorded in AOCI, as a result of the TCJA;
- A decrease in acquisition and transition expenses of approximately $36 million driven by lower external acquisition costs and lower internal labor attributed to the SourceGas Acquisition;
- As a result of the Oil and Gas segment being reported as discontinued operations in 2017, indirect operating costs that would have been charged to this segment were reallocated to other business segments in 2017. These same costs in 2016 are reported as Corporate and Other;
- A decrease of approximately $4.4 million in tax benefits; and
- A decrease in other corporate expenses.

2016 Compared to 2015

Net (loss) available for common stock for the twelve months ended December 31, 2016, was $(44) million compared to net (loss) available for common stock of $(20) million for the same period in the prior year. The variance from the prior year was due to:

- An increase in acquisition and transition expenses of approximately $29 million driven by higher external costs and an increase in internal labor attributed to the SourceGas acquisition;
- An increase in allocated expenses from discontinued operations;
- An increase of approximately $4.4 million in tax benefits; and
- A decrease in other corporate expenses.

Discontinued Operations

Oil and Gas operating results included in discontinued operations for the years ended December 31 were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$25,382	$(8,676)	$34,058	$(9,225)	$43,283
Operations and maintenance	22,872	(4,315)	27,187	(8,274)	35,461
Depreciation, depletion and amortization	7,521	(5,989)	13,510	(15,328)	28,838
Impairment of long-lived assets	20,385	(86,572)	106,957	(142,651)	249,608
Total operating expenses	50,778	(96,876)	147,654	(166,253)	313,907
Operating (loss)	(25,396)	88,200	(113,596)	157,028	(270,624)
Interest income (expense), net	181	(517)	698	(233)	931
Other income (expense), net	(297)	(407)	110	488	(378)
Impairment of equity investments	—	—	—	4,405	(4,405)
Income tax benefit (expense)	8,413	(40,213)	48,626	(52,191)	100,817
(Loss) from discontinued operations available for common stock	$(17,099)	$47,063	$(64,162)	$109,497	$(173,659)

The following tables provide certain operating statistics for Oil and Gas results included in discontinued operations:

Crude Oil and Natural Gas Production	2017	2016	2015
Bbls of oil sold	181,408	318,613	371,493
Mcf of natural gas sold	8,700,612	9,430,288	10,057,378
Bbls of NGL sold	113,233	133,304	101,684
Mcf equivalent sales	10,468,458	12,141,790	12,896,440

Average Price Received [(a)]	2017	2016	2015
Gas/Mcf	$1.49	$1.36	$1.78
Oil/Bbl	$46.50	$57.34	$60.69
NGL/Bbl	$22.28	$12.27	$13.66

(a) Net of hedge settlement gains/losses

	2017	2016	2015
Depletion expense/Mcfe [(a)]	$0.39	$0.79	$1.91

(a) Full cost accounting was no longer applicable at November 1, 2017 and depletion was not recorded after November 1, 2017. The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. See Note 22 of Notes to the Consolidated Financial Statements included in this Annual Report filed on Form 10-K.

The following is a summary of certain annual average costs per Mcfe at December 31:

	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
2017 Average	$0.96	$ 1.33	$ 0.23	$2.52
2016 Average	$1.05	$ 1.20	$ 0.18	$2.43
2015 Average	$1.03	$ 1.23	$ 0.32	$2.58

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, and the cost of operating our own gathering systems is included in operations and maintenance. The gathering, compression, processing and transportation costs shown in the tables above include amounts paid to third parties, as well as costs incurred in operations associated with our own gas gathering, compression, processing and transportation.

The ten-year gas gathering and processing contract for natural gas production in the Piceance Basin in Colorado that became effective in 2014 is part of the sale of our Piceance property. We won’t have any further commitment on this contract when the Piceance asset is sold, which we expect to be before March 31, 2018. This take-or-pay contract requires a minimum fee based on a throughput of 20,000 Mcf per day, regardless of the volume delivered. Gathering, compression and processing costs on a per Mcfe basis, as shown in the tables above, were higher in periods when the minimum contract requirements were not met.

2017 Compared to 2016

Revenue decreased primarily due to a decrease in production from the current year and prior year property sales and a decrease in the average price received, including hedges, for crude oil sold, partially offset by an increase in the average price received, including hedges, for natural gas sold.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing and lower production taxes and ad valorem taxes on lower production and lower revenue driven by property sales.

Depreciation, depletion and amortization decreased due to the reduction of our full cost pool resulting from the prior year ceiling test impairments and no depletion recorded on assets held for sale beginning on November 1, 2017.

Impairment of long-lived assets represents a $20 million non-cash fair value impairment of assets held for sale in 2017 compared to prior year impairments that included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $93 million.

Interest income (expense), net decreased primarily due to lower capitalized interest expense.

Income tax (expense) benefit: Each period reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

2016 Compared to 2015

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 24 percent decrease in the average price received, including hedges, for natural gas sold and a 6 percent decrease in the average price received, including hedges, for crude oil sold. In addition, production decreased by 6 percent as compared to prior year as we limited natural gas production to meet minimum daily quantity contractual gas processing commitments in the Piceance. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing in the prior year, and lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to a reduction of our full cost pool resulting from the ceiling test impairments incurred in current and prior years.

Impairment of long-lived assets represents a non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices and movement of certain unevaluated assets into the full-cost pool. The write-down of $107 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $93 million. The ceiling test write-down for the 12 months ended December 31, 2016 used an average NYMEX natural gas price of $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead, and $42.75 per barrel for crude oil, adjusted to $37.35 per barrel at the wellhead, compared to the $250 million ceiling test write-down in the same period of the prior year which used an average NYMEX natural gas price of $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead, and $50.82 per barrel for crude oil, adjusted to $44.72 per barrel at the wellhead.

Interest income (expense), net increased primarily due to higher capitalized interest compared to the same period in the prior year.

Impairment of equity investments represents a prior year non-cash write-down in equity investments related to interests in a pipeline and gathering system. The impairment resulted from continued declining performance, market conditions, and a change in view of the economics of the facilities that we considered to be other than temporary.

Income tax (expense) benefit: Each period reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

Critical Accounting Policies Involving Significant Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments, or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, "Business Description and Significant Accounting Policies" of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Goodwill

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Beginning in 2016, we changed our annual goodwill impairment testing date from November 30 to October 1 to better align the testing date with our financial planning process. We believe that the change in the date of the annual goodwill impairment test from November 30 to October 1 is not a material change in the application of an accounting principle. The new and old testing dates are close in proximity and both are in the fourth quarter of the year. We would not expect a materially different outcome as a result of testing on October 1 as compared to November 30. The change in assessment date does not have a material effect on the financial statements.

Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount exceeds fair value under the first step, then the second step of the impairment test is performed to measure the amount of any impairment loss.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation, 2) estimates of long-term growth rates for our businesses, 3) the determination of an appropriate weighted-average cost of capital or discount rate, and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries. Varying by reporting unit, weighted average cost of capital in the range of 5% to 8% and long-term growth rate projections in the 1% to 2% range were utilized in the goodwill impairment test performed in the fourth quarter of 2017. Although 1% to 2% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate reviews, as well as other improved efficiency and cost reduction initiatives. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in the impairment assessments are based on available market information, and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. For the years ended December 31, 2017, 2016, and 2015, there were no significant impairment losses recorded. At December 31, 2017, the fair value substantially exceeded the carrying value at all reporting units.

Accounting for Oil and Gas Activities

Impairment testing of assets held for sale

We are in the process of divesting our Oil and Gas segment; therefore, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. For the assets that have not yet been sold, the estimated fair value of our oil and gas assets was determined using the market approaches. The market approach was based on our recent fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made.

At December 31, 2017, the fair value of our held-for-sale assets was less than our carrying value, which required an after-tax write down of $13 million. For additional information, see Note 21 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Full Cost Method of Accounting for Oil and Gas Activities

Prior to the November 1, 2017 decision to divest our oil and gas business, we accounted for oil and gas activities under the full cost method of accounting, whereby all productive and nonproductive costs related to acquisition, exploration, development, abandonment and reclamation activities were capitalized. Accounting for oil and gas activities is subject to industry-specific rules. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling throughout 2016 and 2015, which required after-tax write-downs of $58 million and $158 million for the years ended December 31, 2016 and 2015, respectively. Reserves in 2016 and 2015 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties adjusted for contracted price changes.

Oil, Natural Gas, and Natural Gas Liquids Reserve Estimates

Estimates of our proved crude oil, natural gas and NGL reserves are based on the quantities of each that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prior to November 1, 2017, an independent petroleum engineering company prepared reports that estimate our proved oil, natural gas and NGL reserves annually. The accuracy of any crude oil, natural gas and NGL reserve estimate is a function of the quality of available data, engineering judgment and geological interpretation. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and work over costs, all of which may in fact vary considerably from actual results. In addition, as crude oil, natural gas and NGL prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Estimates for our crude oil, natural gas, and NGL reserves are used throughout our financial statements. For example, since we used the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporated the estimated unit-of-production attributable to the estimates of proved reserves. Under full-cost accounting, the net book value of our crude oil and gas properties was also subject to a “ceiling” limitation based in large part on the value of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Pension and Other Postretirement Benefits

As described in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan, and several defined post-retirement healthcare plans and non-qualified retirement plans. A Master Trust holds the assets for the pension plan. Trusts for the funded portion of the post-retirement healthcare plans have also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rates, health care cost trend rates, expected return on plan assets, compensation increases, retirement rates and mortality rates. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The pension benefit cost for 2018 for our non-contributory funded pension plan is expected to be $6.3 million compared to $2.1 million in 2017. The increase in pension benefit cost is driven primarily by a decrease in the discount rate.

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method used the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Prior to 2016, the service and interest costs were determined using a single weighted-average discount rate based on hypothetical AA Above Median yield curves used to measure the benefit obligation at the beginning of the period. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income.

The Company changed to the new method to provide a more precise measure of service and interest costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. The Company accounted for this change as a change in estimate prospectively beginning in 2016.

The effect of hypothetical changes to selected assumptions on the pension and other postretirement benefit plans would be as follows in thousands of dollars:

Assumptions	Percentage Change	December 31, 2017 Increase/(Decrease) PBO/APBO [(a)]	2018 Increase/(Decrease) Expense - Pretax
Pension			
Discount rate [(b)]	+/- 0.5	(28,825)/31,769	(3,477)/3,784
Expected return on assets	+/- 0.5	N/A	(1,978)/1,981
OPEB			
Discount rate [(b)]	+/- 0.5	(3,025)/3,299	(119)/147
Expected return on assets	+/- 0.5	N/A	(40)/40
Health care cost trend rate [(b)]	+/- 1.0	2,968/(2,534)	377/(322)

(a) Projected benefit obligation (PBO) for the pension plan and accumulated postretirement benefit obligation (APBO) for OPEB plans.
(b) Impact on service cost, interest cost and amortization of gains or losses.

Regulation

Our utility operations are subject to regulation with respect to rates, service area, accounting, and various other matters by state and federal regulatory authorities. The accounting regulations provide that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effects of the manner in which independent third-party regulators establish rates. Regulatory assets generally represent incurred or accrued costs that have been deferred when future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain acquired subsidiaries file as a separate consolidated group. Each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, cash flows or financial position.

The Company has revalued the deferred income taxes at the 21% federal tax rate as of December 31, 2017 and as a result, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA.

As allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Company has recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation, for which the impacts could not be finalized upon issuance of the Company's financial statements but reasonable estimates could be determined. The provisional amounts may change as the Company finalizes the analysis and computations and such changes could be material to the Company's future results of operations, cash flows or financial position.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

See Note 15 in the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Business Combinations

We record acquisitions in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, Business Combinations requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Pertaining to our 2016 acquisition of SourceGas, substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 in the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Liquidity and Capital Resources

OVERVIEW

Our company requires significant cash to support and grow our businesses. Our predominant source of cash is supplied by our operations and supplemented with corporate financings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate. As discussed in more detail below under income taxes, we expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers.

The most significant uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices, as well as during the summer construction season.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, regulatory liabilities, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

Financial Position Summary	2017	2016
Cash and cash equivalents	$15,420	$13,518
Restricted cash and equivalents	$2,820	$2,274
Short-term debt, including current maturities of long-term debt	$217,043	$102,343
Long-term debt [(a)]	$3,109,400	$3,211,189
Stockholders' equity	$1,708,974	$1,614,639
Ratios		
Long-term debt ratio	64%	67%
Total debt ratio	66%	67%

(a) Carrying amount of long-term debt is net of deferred financing costs.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow. However, the potential for unforeseen events affecting cash needs will continue to exist.

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At December 31, 2017, we had sufficient liquidity to cover collateral that could be required to be posted under these wholesale commodity contracts.

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

We manage liquidity needs through hedging activities, primarily in connection with seasonal needs of our utility operations (including seasonal peaks in fuel requirements), interest rate movements and commodity price movements.

Utility Factors

Our cash flows, and in turn liquidity needs in many of our regulated jurisdictions, can be subject to fluctuations in weather and commodity prices. Since weather conditions are uncontrollable, we have implemented commission-approved natural gas hedging and storage programs in many of our regulated jurisdictions to mitigate significant changes in natural gas commodity pricing. We target hedging of approximately 40% to 70% of our forecasted natural gas supply using options, futures and basis swaps.

Interest Rates

Several of our debt instruments have a variable interest rate component which can change significantly depending on the economic climate. We don’t have any interest rate swap agreements at December 31, 2017; 84% of our interest rate exposure has been mitigated through fixed interest rates.

Federal and State Regulations

Federal

We are structured as a utility holding company which owns several regulated utilities. Within this structure, we are subject to various regulations by our commissions that can influence our liquidity. As an example, the issuance of debt by our regulated subsidiaries and the use of our utility assets as collateral generally require the prior approval of the state regulators in the state in which the utility assets are located. Furthermore, as a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is subordinate to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Income Tax

The TCJA legislation was signed into law on December 22, 2017. The new tax law required revaluation of federal deferred tax assets and liabilities using the new lower corporate tax rate of 21%. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets as specifically prescribed in the TCJA.

We are working with utility regulators in each of the states we serve to provide benefits from tax reform to our customers. We expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers. We estimate the lower tax rate will negatively impact the company’s cash flows by approximately $35 million to $45 million annually for the next several years.

Acceleration of depreciation for tax purposes, including 50% bonus depreciation, was previously available for certain property placed in service through September 27, 2017. The TCJA, signed into law on December 22, 2017, enacted 100% bonus depreciation generally to qualifying property acquired and placed in service after September 27, 2017 and before January 1, 2023. After 2022, bonus depreciation would reduce 20% per year with 80% bonus depreciation generally to qualifying property placed in serving during 2023, 60% bonus depreciation generally to qualifying property placed in service during 2024, 40% bonus depreciation generally to qualifying property placed in service during 2025 and 20% generally to qualifying property placed in service after December 31, 2025 and before January 1, 2027. The provision would expand the property that is eligible for this immediate expensing by repealing the requirement that the original use of the property begin with the taxpayer. Instead, the property would be eligible for the additional depreciation if it is the taxpayer’s first use. Under the provision, qualified property eligible for bonus depreciation, including immediate expensing, would not include any property used by a regulated public utility company or any property used in a real property trade or business. These depreciation provisions resulted in cash tax benefits for BHC as indicated in the table below:

(in millions)	2017	2016	2015
Tax benefit	$37	$81	$33

In addition, bonus depreciation will apply to qualifying property whose construction and completion period encompasses multiple tax years. The exception being with respect to costs that would be incurred in 2027 when, under current law, bonus depreciation is scheduled to expire.

The effect of additional depreciation deductions as a result of bonus depreciation will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2022 based on current projections.

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring August 9, 2021, our CP Program and our ability to access the public and private capital markets through debt and securities offerings when necessary.

Cash Collateral

Under contractual agreements and exchange requirements, BHC or its subsidiaries have collateral requirements, which if triggered, require us to post cash collateral positions with the counterparty to meet these obligations.

We have posted the following amounts of cash collateral with counterparties at December 31 (in thousands):

Purpose of Cash Collateral	2017	2016
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$7,694	$12,722
Natural Gas Over-the-Counter Swaps Pursuant to Master Agreements for Derivative Instruments	$562	$—

DEBT

Financing Transactions and Short-Term Liquidity

Our principal sources to meet day-to-day operating cash requirements are cash from operations, our CP Program and our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 with two one-year extension options. This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase total commitments of the facility to up to $1 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at December 31, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption.

Our Revolving Credit Facility had the following borrowings, outstanding letters of credit, and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Revolver Borrowings at December 31, 2017	CP Program Borrowings at December 31, 2017	Letters of Credit at December 31, 2017	Available Capacity at December 31, 2017
Revolving Credit Facility	August 9, 2021	$ 750	$ —	$ 211	$ 27	$ 512

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The weighted average interest rate on CP Program borrowings at December 31, 2017 was 1.76%. Revolving Credit Facility and CP Program financing activity for the twelve months ended December 31, 2017 was (dollars in millions):

	For the Twelve Months Ended December 31, 2017
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$ 282
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances) [(a)]	$ 97
Average amount outstanding - commercial paper (based on daily outstanding balances)	$ 139
Average amount outstanding - revolving credit facility (based on daily outstanding balances) [(a)]	$ 55
Weighted average interest rates - commercial paper	1.34 %
Weighted average interest rates - revolving credit facility [(a)]	2.07 %

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(a) Averages for the Revolving Credit Facility are for the first 29 days of the year after which all borrowings were through the CP Program.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of December 31, 2017.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Capital Resources

Our principal sources for our long-term capital needs have been issuances of long-term debt securities by the Company and its subsidiaries along with proceeds obtained from public and private offerings of equity and proceeds from our ATM equity offering program.

Financing Activities

Financing activities for 2017 consisted of short-term borrowings from our Revolving Credit Facility and CP Program. We also made principal payments of $50 million each on May 16, 2017 and July 17, 2017 on our Corporate term loan due August 9, 2019. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan. On August 4, 2017, we renewed the ATM equity offering program which reset the size of the ATM equity offering program to an aggregate value of up to $300 million. We did not issue any shares of common stock under our ATM equity offering program during 2017.

Financing activities from the prior year consisted of completing the permanent financing for the SourceGas Acquisition. In addition to the net proceeds of $536 million from our November 2015 equity issuances, we completed the Acquisition financing with $546 million of net proceeds from our January 2016 debt offering. We also refinanced the long-term debt assumed with the SourceGas Acquisition primarily through $693 million of net proceeds from our August 19, 2016 debt offerings. In addition to our debt refinancings, we issued a total of 1.97 million shares of common stock throughout 2016 for net proceeds of approximately $119 million through our ATM equity offering program, and sold a 49.9% noncontrolling interest in Black Hills Colorado IPP for $216 million in April 2016.

Future Financing Plans

We anticipate the following financing activities:

- Remarketing the junior subordinated notes maturing in 2018;
- Evaluating an extension of our Revolving Credit Facility and CP program; and
- Evaluating refinancing options for term loan and short-term borrowings under our Revolving Credit Facility and CP program.

Cross-Default Provisions

Our $300 million and $19 million corporate term loans contain cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to make timely payments of debt obligations or triggered other default provisions under any debt agreement totaling, in the aggregate principal amount of $50 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions and a threshold principal amount is $50 million.

The Revolving Credit Facility prohibits us from paying cash dividends if we are in default or if paying dividends would cause us to be in default.

Equity

Based on our current capital spending forecast, we do not anticipate the need to further access the equity capital markets in the next three years.

Shelf Registration

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. We renewed our shelf registration on August 4, 2017. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2017, we had approximately 55 million shares of common stock outstanding and no shares of preferred stock outstanding.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated and approved by our Board of Directors.

On January 31, 2018, our Board of Directors declared a quarterly dividend of $0.475 per share or an annualized equivalent dividend rate of $1.90 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2017	2016	2015
Dividend Payout Ratio	50%	65%	52%

Dividends Per Share	$1.81	$1.68	$1.62

Our three-year compound annualized dividend growth rate was 5.1% and all dividends were paid out of available operating cash flows.

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Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and the use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. As a result of our holding company structure, our right as a common shareholder to receive assets from any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders. Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not comply with certain financial or other covenants. At December 31, 2016, our Revolving Credit Facility and Corporate term loans included a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00, changing to 0.65 to 1.00 in subsequent quarters, beginning March 31, 2017. As of December 31, 2017, we were in compliance with these covenants.

In addition, the agreements governing our equity units generally restrict the payment of cash dividends at any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the junior subordinated notes included in such equity units. Moreover, holders of purchase contracts will be entitled to additional shares of our common stock upon settlement of the purchase contracts if we pay regular quarterly dividends in excess of $0.405 per share while the purchase contracts are outstanding. As of December 31, 2017, we haven't exercised our right to defer payment. On January 31, 2018, we declared a quarterly dividend of $0.475 per share.

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than .60 to 1.00. Our utilities in Arkansas, Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2017, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (1.962% at December 31, 2017). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, money pool balances included (in thousands):

Borrowings From

Subsidiary	(Loans To) Money Pool Outstanding 2017	2016
Black Hills Utility Holdings	$35,693	$52,370
South Dakota Electric	13,397	(28,409)
Wyoming Electric	15,290	20,737
Total Money Pool borrowings from Parent	$64,380	$44,698

CASH FLOW ACTIVITIES

The following table summarizes our cash flows (in thousands):

	2017	2016	2015
Cash provided by (used in)			
Operating activities	$428,261	$320,479	$424,383
Investing activities	$(317,664)	$(1,588,742)	$(476,389)
Financing activities	$(108,695)	$840,998	$483,702

2017 Compared to 2016

Operating Activities:

Net cash provided by operating activities was $108 million higher than in 2016. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $68 million higher than prior year;
- Net outflow from operating assets and liabilities was $16 million lower than prior year, primarily attributable to:
- Cash outflows decreased by approximately $4.8 million as a result of changes in accounts payable and accrued liabilities driven by changes in working capital requirements;
- Cash outflows decreased by approximately $20 million compared to the prior year as a result of lower accounts receivable due to warmer weather partially offset by higher natural gas inventory; and
- Cash outflows increased by approximately $9.5 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts compared to the same period in the prior year;
- Cash outflows decreased by approximately $29 million as a result of a prior year interest rate swap settlement;
- Cash outflows increased by approximately $14 million due to additional pension contributions made in the current year;
- Cash outflows increased approximately $7.8 million for other operating activities compared to the prior year; and
- Cash inflows increased approximately $17 million due to operating activities of discontinued operations.

Investing Activities:

Net cash used in investing activities was $318 million in 2017, compared to net cash used in investing activities of $1.6 billion in 2016 for a variance of $1.3 billion. This variance was primarily due to:

- The prior year's cash outflows included approximately $1.1 billion for the acquisition of SourceGas, net of $760 million long-term debt assumed (see Note 2 in Item 8 of Part II of this Annual Report on Form 10-K);

- Capital expenditures of approximately $326 million in 2017 compared to $455 million in 2016. The $129 million variance to the prior year was due primarily to higher prior year capital expenditures at our Electric Utilities from generation investments at Colorado Electric; and

- Cash inflows increased approximately $16 million due to investing activities of discontinued operations.

Financing Activities:

Net cash used in financing activities was $109 million in 2017, an increase of $950 million from 2016 primarily due to the following:

- Long-term borrowings decreased by $1.8 billion due to the 2016 financings which consisted of $693 million of net proceeds from the August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, $500 million of proceeds from the August 9, 2016 term loan, $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract;

- Payments on long-term debt decreased by $1.1 billion due to the 2016 refinancing of the $760 million of long-term debt assumed in the SourceGas Acquisition and lower current year payments on term loans, $106 million paid on term loans in 2017 compared to $400 million paid on term loans in 2016;

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP that took place in 2016 (see Note 12 in Item 8 of Part II of this Annual Report on Form 10-K);

- Proceeds from common stock issuances decreased by $117 million primarily from issuing common stock under our ATM equity offering program in 2016;

- Net short-term borrowings increased by $95 million primarily due to CP borrowings used to pay down long-term debt;

- Cash dividends on common stock of $97 million were paid in 2017 compared to $88 million paid in 2016;

- Distributions to noncontrolling interests increased by $8.8 million compared to prior year; and

- Cash outflows for other financing activities decreased by approximately $16 million driven primarily by higher financing costs incurred in the prior year from the 2016 debt offerings and refinancings compared to a payment of $5.6 million for a redeemable noncontrolling interest in March 2017.

2016 Compared to 2015

Operating Activities:

Net cash provided by operating activities was $104 million lower than in 2015 primarily attributable to the SourceGas acquisition and the following:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $62 million higher than prior year.

- Net outflow from operating assets and liabilities was $59 million higher than prior year, primarily attributable to:

- Cash outflows increased by approximately $66 million compared to the prior year as a result of higher materials, supplies and fuel and higher accounts receivable partially due to colder weather and higher natural gas volumes sold;

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Cash outflows increased by approximately $34 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts compared to the same period in the prior year;

- Cash outflows decreased by approximately $42 million as a result of changes in accounts payable and accrued liabilities driven primarily by acquisition and transition costs, partially offset by an increase in accrued interest;

- Cash outflows increased by approximately $29 million as a result of interest rate swap settlements;

- Cash outflows increased by $4.0 million due to pension contributions;

- Cash outflows decreased approximately $8.4 million for other operating activities compared to the prior year; and

- Cash inflows decreased approximately $83 million due to operating activities of discontinued operations.

Investing Activities:

Net cash used in investing activities was $1.6 billion in 2016, which was an increase in outflows of $1.1 billion from 2015 primarily due to the following:

- Cash outflows of $1.1 billion for the acquisition of SourceGas, net of $11 million cash received from a working capital adjustment and $760 million of long term debt assumed (see Note 2 in Item 8 of Part II of this Annual Report on Form 10-K);
- In 2016, we had higher capital expenditures of $189 million primarily at our Electric Utilities and Gas Utilities, driven by 2016 wind and natural gas generation additions at our Electric Utilities, and additional capital at our acquired SourceGas Utilities;
- In 2015, we acquired the net assets of two natural gas utilities for $22 million; and
- Cash outflows decreased approximately $179 million due to investing activities of discontinued operations.

Financing Activities:

Net cash provided by financing activities was $841 million in 2016, an increase of $357 million from 2015 primarily due to the following:

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP (see Note 12 in Item 8 of Part II of this Annual Report on Form 10-K);
- Long-term borrowings increased due to the $693 million of net proceeds from our August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, the $500 million of proceeds from our new term loan on August 9, 2016 used to pay off existing debt, the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition, and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract, compared to proceeds of $300 million from long-term borrowings from a term loan in the prior year;
- Payments on long term borrowings increased due to payments made in the current year to refinance the $760 million of long-term debt assumed in the SourceGas Acquisition and $404 million of current year payments made on term loans compared to the payment of $275 million made as part of a term-loan refinancing in the prior year;
- In 2015, we received net proceeds of $290 million from the issuance of our RSNs;
- Proceeds of $120 million primarily from issuing common stock under our ATM equity offering program. 2015 included net proceeds from common stock issuances of $246 million;
- Net short-term borrowings under the revolving credit facility for the year ended December 31, 2016 were $18 million higher than the prior year primarily due to higher working capital requirements in the current year;
- Distributions to noncontrolling interests of $9.6 million;

- Cash outflows for other financing activities increased by approximately $14 million driven primarily by approximately $22 million of financing costs and make whole payments made in 2016 compared to $7 million of bridge facility fees paid in 2015; and
- Cash dividends on common stock of $88 million were paid in 2016 compared to $73 million paid in 2015.

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CAPITAL EXPENDITURES

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next three years.

Historically, a significant portion of our capital expenditures relate primarily to assets that may be included in utility rate base, and if considered prudent by regulators, can be recovered from our utility customers. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate and are subject to rate agreements. During 2017, our Electric Utilities' capital expenditures included improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve or expand the existing gas distribution network. We believe that cash generated from operations and borrowing on our CP Program and our existing Revolving Credit Facility will be adequate to fund ongoing capital expenditures.

Historical Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows (in thousands):

	2017	2016	2015
Property additions: [(a)]			
Electric Utilities	$138,060	$258,739	$171,897
Gas Utilities	184,389	173,930	99,674
Power Generation	1,864	4,719	2,694
Mining	6,708	5,709	5,767
Corporate and Other	6,668	17,353	9,864
Capital expenditures before discontinued operations	337,689	460,450	289,896
Discontinued operations	23,222	6,669	168,925
Total capital expenditures	360,911	467,119	458,821
Common stock dividends	96,744	87,570	72,604
Maturities/redemptions of long-term debt	105,743	1,164,308	275,000
	$563,398	$1,718,997	$806,425

(a) Includes accruals for property, plant and equipment.

Forecasted Capital Expenditure Requirements

Our primary capital expenditure requirements for the three years ended December 31 are expected to be as follows (in thousands):

	2018	2019	2020
Electric Utilities	$149,000	$193,000	$141,000
Gas Utilities	263,000	279,000	245,000
Power Generation	2,000	14,000	5,000
Mining	7,000	7,000	7,000
Corporate and Other	10,000	13,000	8,000
	$431,000	$506,000	$406,000

We continue to evaluate potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates identified above.

CREDIT RATINGS AND COUNTERPARTIES

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect the Company’s ability to maintain or expand its businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the Company’s credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2017:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB	Stable
Moody’s[(b)]	Baa2	Stable
Fitch [(c)]	BBB+	Stable

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(a) On July 21, 2017, S&P affirmed BBB rating and maintained a Stable outlook.
(b) On December 12, 2017, Moody's affirmed our Baa2 rating and maintained a Stable outlook.
(c) On October 4, 2017, Fitch affirmed BBB+ rating and maintained a Stable outlook.

Our fees and interest payments under various corporate debt agreements are based on the higher credit rating of S&P or Moody’s. If either S&P or Moody’s downgraded our senior unsecured debt, we may be required to pay additional fees and incur higher interest rates under current bank credit agreements.

The following table represents the credit ratings of South Dakota Electric at December 31, 2017:

Rating Agency	Senior Secured Rating
S&P	A-
Moody’s	A1
Fitch	A

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2017. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[(a)(b)]	$3,137,519	$5,743	$761,485	$8,436	$2,361,855
Unconditional purchase obligations[(c)]	819,635	149,526	253,357	207,717	209,035
Operating lease obligations[(d)]	15,638	5,030	5,797	1,726	3,085
Other long-term obligations[(e)]	52,024	—	—	—	52,024
Employee benefit plans[(f)]	195,524	18,778	58,564	39,391	78,791
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions	3,263	48	3,215	—	—
CP Program	211,300	211,300	—	—	—
Total contractual cash obligations[(g)]	$4,434,903	$390,425	$1,082,418	$257,270	$2,704,790

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(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period and are not included within the long-term debt balances presented: $127 million in 2018, $122 million in 2019, $113 million in 2020, $101 million in 2021 and $101 million in 2022. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2017.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements The energy charges under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2017 and price assumptions using existing prices at December 31, 2017. Our transmission obligations are based on filed tariffs as of December 31, 2017.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities and Mining segments as discussed in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2027.

(g) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including commodity related contracts that have a negative fair value at December 31, 2017. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Our Gas Utility segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. In addition, a portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. As of December 31, 2017, we are committed to purchase 11.2 million MMBtu, 10.6 million MMBtu, 3.9 million MMBtu, 3.7 million MMBtu and 1.8 million MMBtu in each of the years from 2018 to 2022, respectively.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2017, we had outstanding guarantees as indicated in the table below. For more information on these guarantees, see Note 20 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2017	Year Expiring
Indemnification for subsidiary reclamation/surety bonds [a]	$ 58,221	Ongoing
	$ 58,221	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $27 million in letters of credit issued under our Revolving Credit Facility at December 31, 2017.

Market Risk Disclosures

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures.

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt as described in Notes 6 and 7 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Our exposure to these market risks is affected by a number of factors including the size, duration and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates and the liquidity of the related interest rate and commodity markets.

The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Electric and Gas Utilities

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in six states. All of our utilities have GCA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to match the actual natural gas cost we incurred. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our regulated electric utilities that serves a purpose similar to the GCAs for our regulated gas utilities. To the extent that our fuel and purchased power costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer. These adjustments are subject to periodic prudence reviews by the state utility commissions.

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities’ generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements) expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers’ underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated utilities’ hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2018 through May 2020.

The fair value of our Electric and Gas Utilities derivative contracts at December 31 is summarized below (in thousands):

	2017	2016
Net derivative liabilities	$(6,644)	$(4,733)
Cash collateral	8,256	12,722
	$1,612	$7,989

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

Historically, we have engaged in activities to manage risks associated with changes in interest rates. We utilized pay-fixed interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt refinancings. At December 31, 2017, we had no interest rate swaps in place. At

December 31, 2016, we had a $50 million notional, 4.94% pay-fixed interest rate swap designated to borrowings on our Revolving Credit Facility; this swap expired in January 2017.

Further details of past swap agreements are set forth in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt							
Fixed rate[a]	$5,743	$255,742	$205,743	$1,436	$ —	$2,349,000	$2,817,664
Average interest rate [b]	2.32 %	2.5 %	5.78 %	2.32 %	— %	4.29 %	4.23 %
Variable rate	$—	$300,000	$—	$7,000	$ —	$12,855	$319,855
Average interest rate [b]	— %	2.55 %	— %	1.78 %	— %	1.79 %	2.5 %
Total long-term debt	$5,743	$555,742	$205,743	$8,436	$ —	$2,361,855	$3,137,519
Average interest rate [b]	2.32 %	2.53 %	5.78 %	1.87 %	— %	4.28 %	4.05 %

(a) Excludes unamortized premium or discount.
(b) The average interest rates do not include the effect of interest rate swaps.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

We seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

Our credit exposure at December 31, 2017 was concentrated primarily among retail utility customers, investment grade companies, municipal cooperatives and federal agencies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2017 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management’s Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed 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.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017, based on the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission “COSO”. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2017.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation’s financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2017. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on the Financial Statements

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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. 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
Minneapolis, Minnesota

February 23, 2018

We have served as the Company’s auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2017, of the Company, and our report dated February 23, 2018 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.
Basis for Opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.
Definition and Limitations of Internal Control over Financial Reporting
A company’s internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 23, 2018

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Year ended	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands, except per share amounts)		
Revenue	$1,680,266	$1,538,916	$1,261,322
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	563,288	499,132	456,887
Operations and maintenance	454,605	426,603	323,809
Depreciation, depletion and amortization	188,246	175,533	126,533
Taxes - property and production	51,578	46,160	40,060
Other operating expenses	5,813	55,307	13,613
Total operating expenses	1,263,530	1,202,735	960,902
Operating income	416,736	336,181	300,420
Other income (expense):			
Interest charges -			
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(140,756)	(139,447)	(86,226)
Allowance for funds used during construction - borrowed	2,415	2,981	1,250
Capitalized interest	223	356	326
Interest income	1,016	1,429	1,621
Allowance for funds used during construction - equity	2,321	3,270	897
Other expense	(1,559)	(626)	(158)
Other income	1,346	1,750	2,075
Total other income (expense)	(134,994)	(130,287)	(80,215)
Income before income taxes	281,742	205,894	220,205
Income tax benefit (expense)	(73,367)	(59,101)	(78,657)
Income from continuing operations	208,375	146,793	141,548
Net (loss) from discontinued operations	(17,099)	(64,162)	(173,659)
Net income (loss)	191,276	82,631	(32,111)
Net income attributable to noncontrolling interest	(14,242)	(9,661)	—
Net income (loss) available for common stock	$177,034	$72,970	$(32,111)
Amounts attributable to common shareholders:			
Net income from continuing operations	$194,133	$137,132	$141,548
Net (loss) from discontinued operations	(17,099)	(64,162)	(173,659)
Net income (loss) available for common stock	$177,034	$72,970	$(32,111)
Earnings (loss) per share of common stock, Basic -			
Earnings from continuing operations	$3.65	$2.64	$3.12
(Loss) from discontinued operations	$(0.32)	$(1.23)	$(3.83)
Total earnings (loss) per share of common stock, Basic	$3.33	$1.41	$(0.71)
Earnings (loss) per share of common stock, Diluted -			

Earnings from continuing operations	$3.52	$2.57	$3.12
(Loss) from discontinued operations	$(0.31)	$(1.20)	$(3.83)
Total earnings (loss) per share of common stock, Diluted	$3.21	$1.37	$(0.71)
Weighted average common shares outstanding:			
Basic	53,221	51,922	45,288
Diluted	55,120	53,271	45,288

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year ended	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands)		
Net income (loss)	$191,276	$82,631	$(32,111)
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $1,030, $757 and $(1,375), respectively)	(1,890)	(1,738)	2,657
Benefit plan liability adjustments - prior service (costs) (net of tax of $0, $107 and $0, respectively)	—	(247)	—
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(585), $(600) and $(972), respectively)	1,072	1,378	1,850
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $69, $67 and $88, respectively)	(128)	(154)	(150)
Derivative instruments designated as cash flow hedges:			
Net unrealized gains (losses) on interest rate swaps (net of tax of $0, $10,920 and $(598), respectively)	—	(20,302)	2,290
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(1,029), $(1,365) and $(1,348), respectively)	1,912	2,534	2,299
Net unrealized gains (losses) on commodity derivatives (net of tax of $(135), $212 and $(3,898), respectively)	231	(361)	5,884
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $154, $4,067 and $5,619, respectively)	(516)	(6,938)	(8,841)
Other comprehensive income (loss), net of tax	681	(25,828)	5,989
Comprehensive income (loss)	191,957	56,803	(26,122)
Less: comprehensive income attributable to non-controlling interest	(14,242)	(9,661)	—
Comprehensive income (loss) available for common stock	$177,715	$47,142	$(26,122)

See Note 16 for additional disclosures related to Comprehensive Income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2017	December 31, 2016
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$15,420	$13,518
Restricted cash and equivalents	2,820	2,274
Accounts receivable, net	248,330	259,311
Materials, supplies and fuel	113,283	103,606
Derivative assets, current	304	3,985
Regulatory assets, current	81,016	49,260
Other current assets	25,367	23,928
Current assets held for sale	84,242	10,932
Total current assets	570,782	466,814
Investments	13,090	12,561
Property, plant and equipment	5,567,518	5,315,296
Less accumulated depreciation and depletion	(1,026,088)	(929,119)
Total property, plant and equipment, net	4,541,430	4,386,177
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	7,559	8,392
Derivative assets, non-current	—	222
Regulatory assets, non-current	216,438	246,882
Other assets, non-current	10,149	11,508
Noncurrent assets held for sale	—	109,763
Total other assets, non-current	1,533,600	1,676,221
TOTAL ASSETS	$6,658,902	$6,541,773

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of December 31, 2017	December 31, 2016
	(in thousands, except share amounts)	
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND EQUITY		
Current liabilities:		
Accounts payable	$160,887	$152,129
Accrued liabilities	219,462	235,548
Derivative liabilities, current	2,081	1,104
Accrued income tax, net	1,022	12,552
Regulatory liabilities, current	6,832	13,067
Notes payable	211,300	96,600
Current maturities of long-term debt	5,743	5,743
Current liabilities held for sale	41,774	11,189
Total current liabilities	649,101	527,932
Long-term debt, net of current maturities	3,109,400	3,211,189
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	336,520	561,935
Regulatory liabilities, non-current	478,294	193,689
Benefit plan liabilities	159,646	173,682
Other deferred credits and other liabilities	105,735	115,883
Noncurrent liabilities held for sale	—	23,034
Total deferred credits and other liabilities	1,080,195	1,068,223
Commitments and contingencies (See Notes 6, 7, 8, 9, 14, 18, 19, and 20)		
Redeemable noncontrolling interest	—	4,295
Equity:		
Stockholders' equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued: 53,579,986 and 53,397,467, respectively	53,580	53,397
Additional paid-in capital	1,150,285	1,138,982
Retained earnings	548,617	457,934
Treasury stock at cost - 39,064 and 15,258, respectively	(2,306)	(791)
Accumulated other comprehensive income (loss)	(41,202)	(34,883)
Total stockholders' equity	1,708,974	1,614,639
Noncontrolling interest	111,232	115,495
Total equity	1,820,206	1,730,134
	$6,658,902	$6,541,773

TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands)		
Operating activities:			
Net income (loss)	$191,276	$82,631	$(32,111)
(Income) loss from discontinued operations, net of tax	17,099	64,162	173,659
Income (loss) from continuing operations	208,375	146,793	141,548
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	188,246	175,533	126,533
Deferred financing cost amortization	8,261	6,180	6,364
Stock compensation	7,626	10,885	4,076
Deferred income taxes	80,992	82,704	74,704
Employee benefit plans	10,141	14,291	20,616
Other adjustments, net	(4,773)	(5,519)	(4,872)
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(10,089)	1,211	7,216
Accounts receivable, unbilled revenues and other current assets	4,534	(27,172)	33,255
Accounts payable and other current liabilities	(28,222)	(33,023)	(74,748)
Regulatory assets	(15,407)	3,614	21,883
Regulatory liabilities	(4,536)	(14,082)	1,675
Contributions to defined benefit pension plans	(27,700)	(14,200)	(10,200)
Interest rate swap settlement	—	(28,820)	—
Other operating activities, net	(8,418)	(660)	(9,033)
Net cash provided by operating activities of continuing operations	409,030	317,735	339,017
Net cash provided by (used in) operating activities of discontinued operations	19,231	2,744	85,366
Net cash provided by operating activities	428,261	320,479	424,383
Investing activities:			
Property, plant and equipment additions	(326,010)	(454,952)	(266,375)
Acquisition of net assets, net of long-term debt assumed	—	(1,124,238)	(21,970)
Other investing activities	465	(1,139)	(444)
Net cash (used in) investing activities of continuing operations	(325,545)	(1,580,329)	(288,789)
Net cash provided by (used in) investing activities of discontinued operations	7,881	(8,413)	(187,600)
Net cash provided by (used in) investing activities	(317,664)	(1,588,742)	(476,389)
Financing activities:			
Dividends paid on common stock	(96,744)	(87,570)	(72,604)
Common stock issued	4,408	121,619	248,759
Net increase (decrease) in commercial paper and short-term borrowings	114,700	19,800	1,800
Long-term debt - issuance	—	1,767,608	300,000
Long-term debt - repayments	(105,743)	(1,164,308)	(275,000)
Sale of noncontrolling interest	—	216,370	—
Distributions to noncontrolling interests	(18,397)	(9,561)	—
Equity units - issuance	—	—	290,030
Other financing activities	(6,919)	(22,960)	(9,283)
Net cash provided by (used in) financing activities	(108,695)	840,998	483,702

Net change in cash and cash equivalents	1,902	(427,265)	431,696
Cash and cash equivalents beginning of year	13,518	440,783	9,087
Cash and cash equivalents end of year	$ 15,420	$ 13,518	$ 440,783

See Note 17 for supplemental disclosure of cash flow information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2014	44,714,072	$44,714	42,226	$(1,875)	$748,840	$577,249	$(15,044)	$—	$1,353,884
Net income (loss) available for common stock	—	—	—	—	—	(32,111)	—	—	(32,111)
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	5,989	—	5,989
Dividends on common stock	—	—	—	—	—	(72,604)	—	—	(72,604)
Share-based compensation	126,765	127	(2,506)	(13)	4,126	—	—	—	4,240
Issuance of common stock	6,325,000	6,325	—	—	248,256	—	—	—	254,581
Issuance costs	—	—	—	—	(17,926)	—	—	—	(17,926)
Premium on Equity Units	—	—	—	—	(33,118)	—	—	—	(33,118)
Dividend reinvestment and stock purchase plan	66,024	66	—	—	2,891	—	—	—	2,957
Other stock transactions	—	—	—	—	(25)	—	—	—	(25)
Balance at December 31, 2015	51,231,861	$51,232	39,720	$(1,888)	$953,044	$472,534	$(9,055)	$—	$1,465,867
Net income (loss) available for common stock	—	—	—	—	—	72,970	—	9,661	82,631
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(25,828)	—	(25,828)
Dividends on common stock	—	—	—	—	—	(87,570)	—	—	(87,570)
Share-based compensation	145,634	146	(16,165)	668	4,665	—	—	—	5,479
Issuance of common stock	1,968,738	1,969	—	—	118,021	—	—	—	119,990
Issuance costs	—	—	—	—	(1,566)	—	—	—	(1,566)
Dividend reinvestment and stock purchase plan	51,234	50	—	—	2,933	—	—	—	2,983
Other stock transactions	—	—	(8,297)	429	47	—	—	—	476

Sale of noncontrolling interest	—	—	—	—	61,838	—	—	115,395	177,233
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(9,561)	(9,561)
Balance at December 31, 2016	53,397,467	$53,397	15,258	$(791)	$1,138,982	$457,934	$(34,883)	$115,495	$1,730,134
Net income (loss) available for common stock	—	—	—	—	—	177,034	—	14,242	191,276
Other comprehensive income (loss), net of tax	—	—	—	—	—		681	—	681
Reclassification of certain tax effects from AOCI	—	—	—	—	—	7,000	(7,000)	—	—
Dividends on common stock	—	—	—	—	—	(96,744)	—	—	(96,744)
Share-based compensation	134,266	134	23,806	(1,515)	8,948	—	—	—	7,567
Tax effect of share-based compensation	—	—	—	—	533	3,184	—	—	3,717
Issuance costs	—	—	—	—	(189)	—	—	—	(189)
Dividend reinvestment and stock purchase plan	48,253	49	—	—	3,107	—	—	—	3,156
Redemption of and distributions to noncontrolling interest	—	—	—	—	(1,096)	209	—	(18,505)	(19,392)
Balance at December 31, 2017	53,579,986	$53,580	39,064	$(2,306)	$1,150,285	$548,617	$(41,202)	$111,232	$1,820,206

Dividends per share paid were $1.81, $1.68 and $1.62 for the years ended December 31, 2017, 2016 and 2015, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017, 2016 and 2015

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a customer-focused, growth-oriented, vertically-integrated utility company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, conducts our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation and Mining. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Segment Reporting

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of South Dakota Electric, Wyoming Electric and Colorado Electric, which supply regulated electric utility services to areas in South Dakota, Wyoming, Colorado and Montana. Our Gas Utilities Segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska.

All of our non-utility business segments support our electric utilities. Our Power Generation segment, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Our Mining segment, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. For further descriptions of our reportable business segments, see Note 5.

On November 1, 2017, our Board of Directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90% of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018.

The Oil and Gas segment assets and liabilities have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expenses were no longer recorded. Unless otherwise noted, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company’s continuing operations. For more information on discontinued operations, see Note 21.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. Investment in non-controlled entities over which we have the ability to exercise significant influence over operating and financial policies are accounted for using the equity method of accounting. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for our proportionate share of earnings and losses and distributions. Under this method, a proportionate share of pretax income is recorded as Equity earnings (loss) of unconsolidated subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 5.

Our Consolidated Statements of Income (Loss) include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie. See Note 4 for additional information.

Variable Interest Entities

We evaluate arrangements and contracts with other entities to determine if they are VIEs and if so, if we are the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

Our evaluation of whether our interest qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See additional information in Note 12.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Equivalents

We maintain cash accounts for various specified purposes. Therefore, we classify these amounts as restricted cash.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Electric and Gas Utilities business segments primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and estimated unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Mining and Power Generation business segments consists of amounts due from sales of coal, natural gas, electric energy and capacity.
We maintain an allowance for doubtful accounts which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible

or the time allowed for dispute under the contract has expired.
We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Following is a summary of accounts receivable as of December 31 (in thousands):

2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,347	$36,384	$ (586)	$ 75,145
Gas Utilities	81,256	88,967	(2,495)	167,728
Power Generation	1,196	—	—	1,196
Mining	2,804	—	—	2,804
Corporate	1,457	—	—	1,457
Total	$ 126,060	$125,351	$ (3,081)	$ 248,330

2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,730	$36,463	$ (353)	$ 77,840
Gas Utilities	88,168	88,329	(2,026)	174,471
Power Generation	1,420	—	—	1,420
Mining	3,352	—	—	3,352
Corporate	2,228	—	—	2,228
Total	$ 136,898	$124,792	$ (2,379)	$ 259,311

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price and delivery has occurred or services have been rendered. Sales and franchise taxes collected from our customers are recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, our utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

For long-term non-regulated power sales agreements, revenue is recognized either in accordance with accounting standards for revenue recognition, or in accordance with accounting standards for leases, as appropriate. Under accounting standards for revenue recognition, revenue is generally recognized as the lesser of the amount billed or the average rate expected over the life of the agreement.

Natural gas and crude oil sales included in discontinued operations are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is reasonably assured. BHEP records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, crude oil, condensate and NGLs is adjusted for transportation costs and other related deductions when applicable. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2017	2016
Materials and supplies	$69,732	$64,852
Fuel - Electric Utilities	2,962	3,667
Natural gas in storage	40,589	35,087
Total materials, supplies and fuel	$113,283	$103,606

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are recorded using the weighted-average cost method and are valued at the lower-of-cost or net realizable value. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2017	2016
Accrued employee compensation, benefits and withholdings	$52,467	$54,553
Accrued property taxes	42,029	37,379
Customer deposits and prepayments	44,420	55,191
Accrued interest	33,822	33,982
CIAC current portion	1,552	1,575
Other (none of which is individually significant)	45,172	52,868
Total accrued liabilities	$219,462	$235,548

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. We also classify our base or “cushion gas” as property, plant and equipment. Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. Estimated removal costs associated with non-legal retirement obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income.

Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized, but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives.

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Beginning in 2016, we changed our annual goodwill impairment testing date from November 30 to October 1 to better align the testing date with our financial planning process. We believe that the change in the date of the annual goodwill impairment test from November 30 to October 1 is not a material change in the application of an accounting principle. The new and old testing dates are close in proximity and both are in the fourth quarter of the year. We would not expect a materially different outcome as a result of testing on October 1 as compared to November 30. The change in assessment date does not have a material effect on the financial statements.

We estimated the fair value of the goodwill using discounted cash flow methodology, EBITDA multiple method and an analysis of comparable transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital and long-term earnings and merger multiples for comparable companies.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. See Note 5 for additional business segment information.

Goodwill at our Electric Utilities primarily arose from Colorado Electric, acquired in the Aquila acquisition, which allocated approximately $246 million, or 72% of the transaction to Colorado Electric. Goodwill at our Gas Utilities is primarily from the SourceGas Acquisition, which was allocated entirely to the Gas Utilities adding $940 million in goodwill and the Aquila Transaction, which allocated approximately $94 million, or 28% of the transaction, to the Gas Utilities.

We believe that the goodwill reflects the inherent value of the relatively stable, long-lived cash flows of the regulated electric and gas utility businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our utilities. Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2015	$248,479	$102,515	$ 8,765	$359,759
Additions [(a)]	—	939,695	—	939,695
Ending balance at December 31, 2016	$248,479	$1,042,210	$ 8,765	$1,299,454
Additions	—	—	—	—
Ending balance at December 31, 2017	$248,479	$1,042,210	$ 8,765	$1,299,454

(a) Represents goodwill recorded with the acquisition of SourceGas. See Note 2 for more information.

Our intangible assets represent easements, rights-of-way, customer listings and trademarks. The finite-lived intangible assets are amortized using a straight-line method based on estimated useful lives; these assets are currently being amortized from 2 years to 40 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2017	2016	2015
Intangible assets, net, beginning balance	$8,392	$3,380	$3,176
Additions	—	5,522	434
Amortization expense [(a)]	(833)	(510)	(230)
Intangible assets, net, ending balance	$7,559	$8,392	$3,380

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(a) Amortization expense for existing intangible assets is expected to be $0.8 million for each year of the next five years.

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Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income (Loss). The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations. For oil and gas liabilities classified as held for sale, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and prior to held-for-sale classification were depleted pursuant to the use of the full cost method of accounting. Additional information is included in Note 8 and 21.

Fair Value Measurements

Derivative Financial Instruments

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and 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.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

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Valuation Methodologies for Derivatives

Electric Utilities and Gas Utilities Segments:

- The commodity contracts for the Electric and Gas Utilities, valued using the market approach, include exchange-traded futures, options, basis swaps and over-the-counter swaps (Level 2) for natural gas contracts. For exchanged-traded futures, options and basis swap Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For over-the-counter swaps and option Level 2 assets and liabilities, fair value was derived from, or corroborated by, observable market pricing data. In addition, the fair value for the over-the-counter swaps and option derivatives include a CVA component. The CVA considers the fair value of the derivative and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Corporate Segment:

- Interest rate swaps are valued using the market valuation approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings. We have no interest rate swaps as of December 31, 2017.

Additional information is included in Note 10.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and changes in the derivative instrument’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met and designated accordingly, if they qualify for certain exemptions, including the normal purchases and normal sales exemption, or if regulatory rulings require a different accounting treatment. Changes in the fair value for derivative instruments that do not meet any of these criteria are recognized in the income statement as they occur. Each Consolidated Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists.

Revenues and expenses on contracts that qualify as derivatives may be elected under the normal purchases and normal sales exception and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our electric and gas utility operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exceptions, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated useful life of the related debt. Deferred financing costs are presented on the balance sheet as an adjustment to the related debt liabilities.

Regulatory Accounting

Our Electric Utilities and Gas Utilities follow accounting standards for regulated operations and reflect the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which could require these net regulatory assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities as of December 31 (in thousands):

	Maximum Amortization (in years)	2017	2016
Regulatory assets			
Deferred energy and fuel cost adjustments - current [(a)]	1	$20,187	$17,491
Deferred gas cost adjustments [(a)]	1	31,844	15,329
Gas price derivatives [(a)]	3	11,935	8,843
Deferred taxes on AFUDC [(b)]	45	7,847	15,227
Employee benefit plans [(c)]	12	109,235	108,556
Environmental [(a)]	subject to approval	1,031	1,108
Asset retirement obligations [(a)]	44	517	505
Loss on reacquired debt [(a)]	30	20,667	22,266
Renewable energy standard adjustment [(a)]	5	1,088	1,605
Deferred taxes on flow through accounting [(c)]	54	26,978	37,498
Decommissioning costs	10	13,287	16,859
Gas supply contract termination [(a)]	4	20,001	26,666
Other regulatory assets [(a)]	30	32,837	24,189
		$297,454	$296,142
Regulatory liabilities			
Deferred energy and gas costs [(a)]	1	$3,427	$10,368
Employee benefit plan costs and related deferred taxes [(c)]	12	40,629	68,654
Cost of removal [(a)]	44	130,932	118,410
Excess deferred income taxes [(c)] [(d)]	40	301,553	62
Revenue subject to refund	1	1,488	2,485
Other regulatory liabilities [(c)]	25	7,097	6,777
		$485,126	$206,756

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(a) Recovery of costs, but we are not allowed a rate of return.

(b) In addition to recovery of costs, we are allowed a rate of return.

(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

(d) The increase in the regulatory tax liability is primarily related to the revaluation of deferred income tax balances at the lower income tax rate. As of December 31, 2017, all of the liability has been classified as non-current due to uncertainties around the timing and other regulatory decisions that will affect the amount of regulatory tax liability amortized and returned to customers through rate reductions or other revenue offsets in 2018.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Current - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission. Our electric and gas utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.

Deferred Gas Cost Adjustment - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions.

Gas Price Derivatives - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. The 3-year term represents the maximum forward term hedged.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans in regulatory assets rather than in AOCI, including costs being amortized from the Aquila and SourceGas Transactions.

Environmental - Environmental expenditures are costs associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 8 for additional details.

Loss on Reacquired Debt - Loss on reacquired debt is recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants.

Gas Supply Contract Termination - Black Hills Gas Holdings had agreements under the previous ownership that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The majority of these purchases were committed to distribution customers in Nebraska, Colorado, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, and exceeded market prices. We recorded a liability for this contract in our purchase price allocation. We were granted approval to terminate these agreements from the NPSC, CPUC and WPSC, on the basis that these agreements are not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a period of five years. We terminated the contract and settled the liability on April 29, 2016.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs - Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

Employee Benefit Plan Costs and Related Deferred Taxes - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Cost of Removal - Cost of removal represents the estimated cumulative net provisions for future removal costs for which there is no legal obligation for removal included in depreciation expense.

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain subsidiaries acquired file as a separate consolidated group. Where applicable, each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

It is our policy to apply the flow-through method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. An exception to this general policy is the deferral method, which applies to our regulated businesses. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Consolidated Statements of Income (Loss).

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 15 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing and discontinued operations is computed by dividing Net income (loss) from continuing and discontinued operations by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to equity units, and outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings (loss) per share is as follows for the years ended December 31 (in thousands):

	2017	2016	2015
Net income (loss) available for common stock	$177,034	$72,970	$(32,111)
Weighted average shares - basic	53,221	51,922	45,288
Dilutive effect of:			
Equity Units	1,783	1,222	—
Equity compensation	116	127	—
Weighted average shares - diluted	55,120	53,271	45,288
Net income (loss) available for common stock, per share - Diluted	$3.21	$1.37	$(0.71)

Due to our Net loss available for common stock for the year ended December 31, 2015, potentially diluted securities were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 83,000 equity compensation shares were excluded from the computation for the year ended December 31, 2015.

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive for the years ended December 31 (in thousands):

	2017	2016	2015
Equity compensation	11	3	112
Equity units	—	—	6,440
Anti-dilutive shares excluded from computation of earnings (loss) per share	11	3	6,552

Business Combinations

We record acquisitions in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, Business Combinations requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 for additional detail on the accounting for the SourceGas Acquisition.

Noncontrolling Interest

We account for changes in our controlling interests of subsidiaries according to ASC 810, Consolidations. ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on Noncontrolling Interests.

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, Compensation-Stock Compensation, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures.

Recently Issued Accounting Standards

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer. The new disclosure requirements will provide information about the nature, amount, timing and uncertainty of revenue and cash flows from revenue contracts with customers. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017. Entities have the option of using either a full retrospective or modified retrospective approach to adopting this guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

We have implemented this standard effective January 1, 2018 on a modified retrospective basis. We have completed our assessment of all revenue from existing contracts with customers and there is no significant impact to our revenue recognition practices, financial position, results of operations or cash flows. A majority of our revenues are from regulated tariff offerings that provide natural gas or electricity with a defined contractual term, generally limited to the services requested and received to date for such arrangements. For such arrangements, the performance obligation transfer of control and revenue recognition occurs when the electricity or natural gas is delivered, consistent with the previous revenue recognition guidance. The same transfer of control and revenue recognition based on delivery principles also apply to our revenue contracts for wholesale and off-system power sales arrangements, coal supply agreements, and other non-regulated services. Therefore, we did not have a cumulative adjustment to Retained earnings or an impact on our revenue recognition policies as a result of the adoption of the new standard. The new standard will require us to provide more robust disclosures than required by previous guidance, including disclosures related to disaggregation of revenue into appropriate categories, performance obligations, and the judgments made in revenue recognition determinations.

Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, ASU 2017-07

In March 2017, the FASB issued ASU 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost. The changes to the standard require employers to report the service cost component in the same line item(s) as other compensation costs, and require the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. This ASU will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and post-retirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and post-retirement benefit costs in assets will be applied on a prospective basis. This new guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. We have implemented this standard effective January 1, 2018. For our rate-regulated entities, we will capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities and maintain a FERC to GAAP reporting difference for these capitalized costs. The presentation changes required for net periodic pension and post-retirement costs will result in offsetting changes to Operating income and Other income, which are not expected to be material.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). This ASU requires changes in the presentation of certain items, including but not limited to, debt prepayment or debt extinguishment costs; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. The ASU will be effective for fiscal years beginning after December 15, 2017. We have implemented this standard effective January 1, 2018 using the retrospective transition method. This standard will not have a material impact on our financial position, results of operations or cash flows.

Leases, ASU 2016-02

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases, whereas today only financing-type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Under the current guidance, lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard.

We currently expect to adopt this standard on January 1, 2019 and anticipate electing the transition approach to not assess existing or expired land easements that were not previously accounted for as a lease. We continue to evaluate the impact of this new standard on our financial position, results of operations and cash flows as well as monitor emerging guidance on such topics as easements and rights of way, pipeline laterals, purchase power agreements, secondary use assets, and other industry-related areas. We continue the process of identifying and categorizing our lease contracts and evaluating our current business processes and systems.

Derivatives and Hedging: Targeted Improvement to Accounting for Hedging Activities, 2017-12

In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvement to Accounting for Hedging Activities. This standard better aligns risk management activities and financial reporting for hedging relationships, simplifies hedge accounting requirements and improves disclosures of hedging arrangements. This ASU is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We are currently reviewing this standard to assess the impact on our financial position, results of operations and cash flows.

Simplifying the Test for Goodwill Impairment, 2017-04

In January 2017, the FASB issued ASU 2017-04, Simplifying the Test for Goodwill Impairment by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this guidance to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, ASU 2018-02

In February 2018, the FASB issued ASU 2018-02, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. This ASU was issued to address industry concerns regarding the application of current accounting guidance to certain provisions of the new tax reform legislation. This ASU permits entities to make a one-time reclassification from AOCI to retained earnings for stranded tax effects resulting from the newly enacted corporate tax rate. The amount of the reclassification is calculated on the basis of the difference between the historical and newly enacted tax rates for deferred tax liabilities and assets related to items within AOCI. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods therein, and early adoption is permitted. We have implemented this ASU effective December 22, 2017, the enactment date of the TCJA, which resulted in a reclassification of $7.0 million of stranded tax effects from AOCI to retained earnings. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

Improvements to Employee Share-Based Payment Accounting, ASU 2016-09

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We implemented this ASU effective January 1, 2017, recording a cumulative-effect adjustment of $3.2 million to Retained earnings in the Consolidated Balance Sheets as of the date of adoption, representing previously recorded forfeitures and excess tax benefits generated in years prior to 2017 that were previously not recognized in stockholders' equity due to NOLs in those years. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

(2) ACQUISITION

Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, including the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments for capital expenditures, indebtedness and working capital. Post-closing adjustments of approximately $11 million were agreed to and received from the sellers in June 2016. SourceGas is a 100% owned subsidiary of Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation and has been renamed Black Hills Gas Holdings, LLC. Black Hills Gas Holdings primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado.

Cash consideration of $1.135 billion paid on February 12, 2016 to close the SourceGas Acquisition included net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.325 million shares of our common stock, 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 13, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

In connection with the acquisition, the Company recorded pre-tax, incremental acquisition costs of approximately $45 million and $10 million for the years ending December 31, 2016 and 2015, respectively. These costs consisted of transaction costs, professional fees, employee-related expenses and other miscellaneous costs. The costs are recorded primarily in Other operating expenses and Interest expense on the Consolidated Statements of Income (Loss).

Our consolidated operating results for the year ended December 31, 2016 include revenues of $348 million and net income (loss) of $15 million, attributable to SourceGas for the period from February 12 through December 31, 2016. The SourceGas operating results are reported in our Gas Utilities segment. We believe the SourceGas Acquisition enhances Black Hills Corporation's utility growth strategy, providing greater operating scale, driving more efficient delivery of services and benefiting customers.

We accounted for the SourceGas Acquisition in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. Substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

The final purchase price allocation of the fair value of the assets acquired and liabilities assumed is included in the table below. The cash consideration paid of $1.124 billion, net of long-term debt assumed of $760 million and a working capital adjustment received of approximately $11 million, resulted in goodwill of $940 million. We had up to one year from the acquisition date to finalize the purchase price allocation. The working capital adjustment received in 2016 of $11 million reflected changes in valuation estimates for intangible assets, accrued liabilities and deferred taxes. Approximately $252 million of the goodwill balance is amortizable for tax purposes, relating to the partnership interests that were directly acquired in the transaction. The remainder of the goodwill balance is not amortizable for tax purposes. Goodwill generated from the acquisition reflects the benefits of increased operating scale and organic growth opportunities.

	(in thousands)
Purchase Price	$1,894,882
Less: Long-term debt assumed	(760,000)
Less: Working capital adjustment received	(10,644)
Consideration paid, net of working capital adjustment received	$1,124,238
Allocation of Purchase Price:	
Current Assets	$112,983
Property, plant & equipment, net	1,058,093
Goodwill	939,695
Deferred charges and other assets, excluding goodwill	133,299
Current liabilities	(172,454)
Long-term debt	(758,874)
Deferred credits and other liabilities	(188,504)
Total consideration paid, net of working-capital adjustment received	$1,124,238

Conditions of SourceGas Acquisition Regulatory Approval

The acquisition was subject to regulatory approvals from the public utility commissions in Arkansas (APSC), Colorado (CPUC), Nebraska (NPSC), and Wyoming (WPSC). Approvals were obtained from all commissions, subject to various conditions as set forth below:

The APSC order includes a twelve-month base rate moratorium, an annual $0.25 million customer credit for a term of up to five years or until we file the next rate review, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate review, as well as various other terms and reporting requirements.

The CPUC order includes a two-year base rate moratorium for our regulated transmission and wholesale natural gas provider, a three-year base rate moratorium for our regulated gas distribution utility, an annual $0.2 million customer credit for a term of up to five-years or until we file the next rate review, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The NPSC order includes a three-year base rate moratorium, a three-year continuation of the Choice Gas Program, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate review, as well as various other terms and reporting requirements.

The WPSC order includes a three-year continuation of the Choice Gas Program, as well as various other terms and reporting requirements.

All four orders also disallowed recovery of goodwill and transaction costs. Recovery of transition costs is disallowed in Arkansas, Colorado and Nebraska. However, Wyoming allows for request of recovery of transition costs. Transition costs are those non-recurring costs related to the transition and integration of SourceGas. In the conditions mentioned above, the orders that include base rate moratoriums over a specified period of time do not impact our ability to adjust rates through riders or gas supply cost recovery mechanisms as allowed under the current enacted state tariffs. In certain cases, we may file for leave to increase general base rates and/or cost of sales recovery limited to material adverse changes, but only if there are changes in law or regulations or the occurrence of other extraordinary events outside of our control which result in a material adverse change in revenues, revenue requirement and/or increase in operating costs.

Settlement of Gas Supply Contract

On April 29, 2016, we settled for $40 million, a former SourceGas contract that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. This contract's intangible negative fair value is included with Current liabilities in the purchase price allocation. Approximately 75% of these purchases were committed to distribution customers in Nebraska, Colorado and Wyoming, which are subject to cost recovery mechanisms, while the remaining 25% was not subject to regulatory recovery. The prices to be paid under this contract varied, ranging from $6 to $8 per MMBtu at the time of acquisition and exceeded market prices. We applied for and were granted approval to terminate this agreement from the NPSC, CPUC and WPSC, on the basis that the agreement was not beneficial to customers in the long term. We received written orders allowing recovery of the net buyout costs associated with the contract termination that were allocated to regulated subsidiaries. These costs were recorded as a regulatory asset of approximately $30 million that is being recovered over a five-year period beginning April 29, 2016.

Pro Forma Results (unaudited)

We calculated the pro forma impact of the SourceGas Acquisition and the associated debt and equity financings on our operating results for the year ended December 31, 2016 and 2015. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2015:

	Pro Forma Results December 31,	
	2016	2015
	(in thousands, except per share amounts)	
Revenue	$1,617,878	$1,720,618
Income from continuing operations	$177,040	$160,290
Net income (loss)	$112,878	$(13,369)
Earnings from continuing operations per share, Basic	$3.41	$3.15
Earnings from continuing operations per share, Diluted	$3.32	$3.15

We derived the pro forma results for the SourceGas Acquisition based on historical financial information obtained from the sellers and certain management assumptions. Our pro forma adjustments relate to incremental interest expense associated with the financings to effect the transaction, and for the year ended December 31, 2015, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2015, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the acquisition, and exclude any unique one-time items resulting from the acquisition that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the year ended December 31, 2016 reflect unfavorable weather impacts resulting in lower gas usage by our customers than in the same periods of the prior year. In addition, we calculated the tax impact of these adjustments at an estimated combined federal and state income tax rate of 37%.

These pro forma results are for illustrative purposes only and do not purport to be indicative of the results that would have been obtained had the SourceGas Acquisition been completed on January 1, 2015, or that may be obtained in the future.

Seller’s noncontrolling interest

As part of the SourceGas Transaction, a seller retained a 0.5% noncontrolling interest and we entered into an associated option agreement with the holder for the 0.5% retained interest. In March 2017, we exercised our call option and purchased the remaining 0.5% equity interest in SourceGas for $5.6 million.

(3) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

Electric Utilities	2017 Property, Plant and Equipment	2017 Weighted Average Useful Life (in years)	2016 Property, Plant and Equipment	2016 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:						
Production	$1,315,044	39	$1,303,101	41	30	55
Electric transmission	407,203	51	354,801	52	40	70
Electric distribution	755,213	48	712,575	48	15	75
Plant acquisition adjustment [a]	4,870	32	4,870	32	32	32
General	232,842	31	164,761	25	3	65
Capital lease - plant in service [b]	261,441	20	261,441	20	20	20
Total electric plant in service	2,976,613		2,801,549			
Construction work in progress	13,595		74,045			
Total electric plant	2,990,208		2,875,594			
Less accumulated depreciation and amortization	644,022		578,162			
Electric plant net of accumulated depreciation and amortization	$2,346,186		$2,297,432			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 13 years remaining.

(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the PPA between Colorado Electric and Black Hills Colorado IPP. The capital lease ends in conjunction with the expiration of the PPA on December 31, 2031.

Gas Utilities	2017 Property, Plant and Equipment	Weighted Average Useful Life (in years)	2016 Property, Plant and Equipment	Weighted Average Useful Life (in years)	Lives (in years) Minimum	Maximum
Gas plant:						
Production	$10,495	35	$10,821	35	17	71
Gas transmission	366,433	48	338,729	48	22	70
Gas distribution	1,413,431	42	1,303,366	42	33	47
Cushion gas - depreciable [(a)]	3,539	28	3,539	28	28	28
Cushion gas - not depreciated [(a)]	47,466	0	47,055	0	0	0
Storage	28,520	31	27,686	31	15	48
General	336,869	19	339,382	19	3	44
Total gas plant in service	2,206,753		2,070,578			
Construction work in progress	44,440		28,446			
Total gas plant	2,251,193		2,099,024			
Less accumulated depreciation and amortization	229,170		194,585			
Gas plant net of accumulated depreciation and amortization	$2,022,023		$1,904,439			

(a) Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability. Depreciation of cushion gas is determined by the respective regulatory jurisdiction in which the cushion gas resides.

2017	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Maximum
Power Generation	$ 155,569	$ 224	$ 155,793	$ 57,813	$ 97,980	33	2	40
Mining	158,370	—	158,370	108,844	49,526	14	2	59

2016	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Maximum
	$ 161,430	$ 1,298	$ 162,728	$ 55,157	$ 107,571	33	2	40

Power Generation									
Mining	151,709	4,642	156,351	105,219	51,132	13		2	59

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2017							Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Add Accumulated Depreciation - Capital Lease Elimination (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$ 5,580	$ 6,374	$ 11,954	$ 309	$ 14,070	$ 25,715	8	3	30

(a) Reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP of $14 million.

2016							Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Add Accumulated Depreciation - Capital Lease Elimination (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$ 9,625	$ 11,974	$ 21,599	$ 2,106	$ 6,110	$ 25,603	8	3	30

(a) Reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP of $6.1 million.

(4) JOINTLY OWNED FACILITIES

Utility Plant

Our consolidated financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- South Dakota Electric owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. South Dakota Electric receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying South Dakota Electric with coal for its share of the Wyodak Plant, our Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

- South Dakota Electric also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

- South Dakota Electric owns 52% of the Wygen III coal-fired generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations. Our Mining subsidiary supplies coal to Wygen III for the life of the plant.

- Colorado Electric owns 50% of the Busch Ranch Wind Farm while AltaGas owns the remaining undivided ownership interest and is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm for the life of the facility. We retain responsibility for operations of the wind farm.

Non-Regulated Plants

Our consolidated financial statements include our share of a jointly-owned non-regulated power generation facility as described below. Our share of direct expenses for the jointly-owned facility is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income (Loss). Each of the respective owners is responsible for providing its own financing.

- Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Mining subsidiary during the life of the facility. We retain responsibility for plant operations.

At December 31, 2017, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$114,405	$ 727	$ 58,955
Transmission Tie	$20,037	$ 242	$ 6,215
Wygen I	$109,552	$ 209	$ 40,465
Wygen III	$138,688	$ 406	$ 19,239
Busch Ranch Wind Farm	$18,899	$ —	$ 3,858

(5) BUSINESS SEGMENT INFORMATION

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Segment information was as follows (in thousands):

Total Assets (net of intercompany eliminations) as of December 31,	2017	2016
Electric [(a)]	$2,906,275	$2,859,559
Gas	3,426,466	3,307,967
Power Generation [(a)]	60,852	73,445
Mining	65,455	67,347
Corporate and Other	115,612	112,760
Discontinued operations [(b)]	84,242	120,695
Total assets	$6,658,902	$6,541,773

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

(b) On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. See Note 21 for additional information.

Capital Expenditures and Asset Acquisitions [(a)] for the years ended December 31,	2017	2016
Capital expenditures		
Electric Utilities	$138,060	$258,739
Gas Utilities	184,389	173,930
Power Generation	1,864	4,719
Mining	6,708	5,709
Corporate and Other	6,668	17,353
Total capital expenditures	337,689	460,450
Asset acquisitions		
Gas Utilities [(b)]	—	1,124,238
Total capital expenditures and asset acquisitions of continuing operations	337,689	1,584,688
Total capital expenditures of discontinued operations	23,222	6,669
Total capital expenditures and asset acquisitions	$360,911	$1,591,357

(a) Includes accruals for property, plant and equipment.

(b) SourceGas was acquired on February 12, 2016. Net cash paid of $1.124 billion was net of long-term debt assumed and working capital adjustments received. See Note 2.

Property, Plant and Equipment as of December 31,	2017	2016
Electric Utilities [(a)]	$2,990,208	$2,875,594
Gas Utilities	2,251,193	2,099,024
Power Generation [(a)]	155,793	162,728
Mining	158,370	156,351
Corporate and Other	11,954	21,599
Total property, plant and equipment	$5,567,518	$5,315,296

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Year ended December 31, 2017	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$689,945	$947,595	$7,263	$35,463	$—	$—	$—	$1,680,266
Intercompany revenue	14,705	35	84,283	31,158	344,685	(474,866)	—	—
Total revenue	704,650	947,630	91,546	66,621	344,685	(474,866)	—	1,680,266
Fuel, purchased power and cost of natural gas sold	268,405	409,603	—	—	151	(114,871)	—	563,288
Operations and maintenance	172,307	269,190	32,382	44,882	296,067	(302,832)	—	511,996
Depreciation, depletion and amortization	93,315	83,732	5,993	8,239	21,031	(24,064)	—	188,246
Operating income (loss)	170,623	185,105	53,171	13,500	27,436	(33,099)	—	416,736
Interest expense	(55,229)	(80,829)	(3,959)	(228)	(152,416)	154,543	—	(138,118)
Interest income	2,955	2,254	1,123	23	115,382	(120,721)	—	1,016
Other income (expense), net	1,730	(829)	(54)	2,191	330,373	(331,303)	—	2,108
Income tax benefit (expense) [(a)]	(9,997)	(39,799)	10,333	(1,100)	(32,433)	(371)	—	(73,367)
Income (loss) from continuing operations	110,082	65,902	60,614	14,386	288,342	(330,951)	—	208,375
Income (loss) from discontinued operations, net of tax [(b)]	—	—	—	—	—	—	(17,099)	(17,099)
Net income (loss)	110,082	65,902	60,614	14,386	288,342	(330,951)	(17,099)	191,276
Net income attributable to noncontrolling interest	—	(107)	(14,135)	—	—	—	—	(14,242)
Net income (loss) available for common stock	$110,082	$65,795	$46,479	$14,386	$288,342	$(330,951)	$(17,099)	$177,034

(a) The effective tax rate is lower in 2017 resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017.
(b) Discontinued operations includes oil and gas property impairments (see Note 21).

Year ended December 31, 2016	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$664,330	$838,343	$7,176	$29,067	$—	$—	$—	$1,538,916
Intercompany revenue	12,951	—	83,955	31,213	347,500	(475,619)	—	—
Total revenue	677,281	838,343	91,131	60,280	347,500	(475,619)	—	1,538,916
Fuel, purchased power and cost of natural gas sold	261,349	352,165	—	—	456	(114,838)	—	499,132
Operations and maintenance	158,134	245,826	32,636	39,576	378,744	(326,846)	—	528,070
Depreciation, depletion and amortization	84,645	78,335	4,104	9,346	22,930	(23,827)	—	175,533
Operating income (loss)	173,153	162,017	54,391	11,358	(54,630)	(10,108)	—	336,181
Interest expense	(56,237)	(76,586)	(3,758)	(401)	(114,597)	115,469	—	(136,110)
Interest income	5,946	1,573	1,983	24	97,147	(105,244)	—	1,429
Other income (expense), net	3,193	184	2	2,209	179,838	(181,032)	—	4,394
Income tax benefit (expense)	(40,228)	(27,462)	(17,129)	(3,137)	28,398	457	—	(59,101)
Income (loss) from continuing operations	85,827	59,726	35,489	10,053	136,156	(180,458)	—	146,793
(Loss) from discontinued operations, net of tax [(a)]	—	—	—	—	—	—	(64,162)	(64,162)
Net income (loss)	85,827	59,726	35,489	10,053	136,156	(180,458)	(64,162)	82,631
Net income attributable to noncontrolling interest	—	(102)	(9,559)	—	—	—	—	(9,661)
Net income (loss) available for common stock	$85,827	$59,624	$25,930	$10,053	$136,156	$(180,458)	$(64,162)	$72,970

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(a) Discontinued operations includes oil and gas property impairments (see Note 21).

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Year ended December 31, 2015	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$668,226	$551,300	$7,483	$34,313	$—	$—	$—	$1,261,322
Intercompany revenue	11,617	—	83,307	30,753	227,708	(353,385)	—	—
Total revenue	679,843	551,300	90,790	65,066	227,708	(353,385)	—	1,261,322
Fuel, purchased power and cost of natural gas sold	269,409	299,645	—	—	122	(112,289)	—	456,887
Operations and maintenance	160,924	140,723	32,140	41,630	231,855	(229,790)	—	377,482
Depreciation, depletion and amortization	80,929	32,326	4,329	9,806	9,723	(10,580)	—	126,533
Operating income (loss)	168,581	78,606	54,321	13,630	(13,992)	(726)	—	300,420
Interest expense	(55,159)	(17,912)	(4,218)	(433)	(61,496)	54,568	—	(84,650)
Interest income	4,114	601	1,015	34	48,799	(52,942)	—	1,621
Other income (expense), net	1,216	315	71	2,247	70,929	(71,964)	—	2,814
Income tax benefit (expense)	(41,173)	(22,304)	(18,539)	(3,608)	6,606	361	—	(78,657)
Income (loss) from continuing operations	77,579	39,306	32,650	11,870	50,846	(70,703)	—	141,548
Income (loss) from discontinued operations, net of tax [(a)]	—	—	—	—	—	—	(173,659)	(173,659)
Net income (loss)	77,579	39,306	32,650	11,870	50,846	(70,703)	(173,659)	(32,111)
Net income attributable to noncontrolling interest	—	—	—	—	—	—	—	—
Net income (loss) available for common stock	$77,579	$39,306	$32,650	$11,870	$50,846	$(70,703)	$(173,659)	$(32,111)

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(a) Discontinued operations includes oil and gas property impairments (see Note 21).

Corporate expense reallocation

In accordance with GAAP, indirect corporate operating costs previously allocated to BHEP were not reclassified to discontinued operations. These corporate operating costs for 2017 were reallocated to our operating segments; allocated interest was reclassified to Corporate and Other. Indirect corporate operating costs for 2016 and 2015 were reclassified to Corporate and Other. The reallocation of these costs to our operating segments in 2017 and an estimate of how these costs could have been allocated to segments other than Corporate and Other in 2016 and 2015 is as follows (in thousands):

Business Segment	Year Ended December 31, 2017	December 31, 2016	December 31, 2015
Electric Utilities	$1,323	$ 2,079	$ 3,344
Gas Utilities	1,571	2,292	1,815
Power Generation	177	320	543

Mining	101	196	321
Total reportable segments	3,172	4,887	6,023
Corporate and Other [(a)]	6,405	6,037	3,957
Total	$9,577	$ 10,924	$ 9,980

(a) Includes interest allocations in 2017, 2016 and 2015 of approximately $4.9 million, $5.6 million and $3.4 million, respectively.

(6) LONG-TERM DEBT

Long-term debt outstanding was as follows (dollars in thousands):

	Due Date	Interest Rate at December 31, 2017	Balance Outstanding December 31, 2017	December 31, 2016
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$525,000	$525,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Remarketable junior subordinated notes [b]	November 1, 2028	3.50%	299,000	299,000
Senior unsecured notes due 2019	January 11, 2019	2.50%	250,000	250,000
Senior unsecured notes due 2026	January 15, 2026	3.95%	300,000	300,000
Senior unsecured notes due 2027	January 15, 2027	3.15%	400,000	400,000
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	300,000
Corporate term loan due 2019 [a]	August 9, 2019	2.55%	300,000	400,000
Corporate term loan due 2021	June 7, 2021	2.32%	18,664	24,406
Total Corporate debt			2,592,664	2,698,406
Less unamortized debt discount			(3,808)	(4,413)
Total Corporate debt, net			2,588,856	2,693,993
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	75,000
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021 [c]	September 1, 2021	1.78%	7,000	7,000
Industrial development revenue bonds due 2027 [c]	March 1, 2027	1.78%	10,000	10,000
Series 94A Debt, variable rate [c]	June 1, 2024	1.83%	2,855	2,855
Total Electric Utilities debt			544,855	544,855
Less unamortized debt discount			(90)	(94)
Total Electric Utilities debt, net			544,765	544,761
Total long-term debt			3,133,621	3,238,754
Less current maturities			5,743	5,743
Less deferred financing costs [d]			18,478	21,822
Long-term debt, net of current maturities and deferred financing costs			$3,109,400	$3,211,189

(a) Variable interest rate, based on LIBOR plus a spread.

(b) See Note 12 for RSN details.

(c) Variable interest rate.

(d) Includes deferred financing costs associated with our Revolving Credit Facility of $1.7 million and $2.3 million as of December 31, 2017 and December 31, 2016, respectively.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2018	$5,743
2019	$555,742
2020	$205,743
2021	$8,436
2022	$—
Thereafter	$2,361,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2017.

Substantially all of the tangible utility property of South Dakota Electric and Wyoming Electric is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of South Dakota Electric and Wyoming Electric may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by South Dakota Electric and Wyoming Electric are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Assumption of Long-Term Debt

At the closing of the SourceGas Acquisition on February 12, 2016, we assumed $760 million in long-term debt, consisting of the following:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 1, 2017.

- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.

- $340 million unsecured corporate term loan due June 30, 2017. Interest under this term loan was LIBOR plus a margin of 0.875%.

The $760 million in long-term debt assumed in the SourceGas Acquisition was repaid in August 2016.

Debt Transactions

On May 16, 2017, we paid down $50 million on our Corporate term loan due August 9, 2019. On July 17, 2017, we paid down an additional $50 million on the same term loan. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan.

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046 (together the "Notes"). The proceeds of the Notes were used for the following:

- Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;

- Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;

- Repay $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;

- Pay down $100 million of the $500 million three-year unsecured term loan discussed below;

- Payment of $29 million for the settlement of $400 million notional interest rate swap; and

- Remainder was used for general corporate purposes.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan were used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas

Acquisition and the $260 million term loan expiring on April 12, 2017. This new term loan has substantially similar terms and covenants as the amended and restated Revolving Credit Facility.

In accordance with regulatory orders related to the early termination and settlement of the gas supply contract described in Note 1, on June 7, 2016, we entered into a 2.32%, $29 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the early termination of the gas supply contract, resulting in a regulatory asset. Principal and interest are payable quarterly at approximately $1.6 million.

On January 13, 2016, we completed a public debt offering of $550 million principal amount of senior unsecured notes. The debt offering consisted of $300 million of 3.95%, ten-year senior notes due 2026, and $250 million of 2.50%, three-year senior notes due 2019. After discounts and underwriter fees, net proceeds from the offering totaled $546 million and were used as funding for the SourceGas Acquisition. The discounts are amortized over the life of each respective note.

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income (Loss) were as follows (in thousands):

	Deferred Financing Costs Remaining at December 31, 2017	Amortization Expense for the years ended December 31,		
		2017	2016	2015
Revolving Credit Facility	$ 1,703	$638	$537	$504
Senior unsecured notes due 2023	2,427	494	494	494
Senior unsecured notes due 2019	59	704	643	—
Senior unsecured notes due 2020	425	167	167	167
Senior unsecured notes due 2026	2,031	287	262	—
Senior unsecured notes due 2027	2,918	363	121	—
Senior unsecured notes due 2046	3,082	111	37	—
Corporate term loan due 2019	86	201	144	—
Bridge Term Loan	—	—	843	4,213
RSNs due 2028	1,326	122	122	10
First mortgage bonds due 2044 (South Dakota Electric)	639	24	24	24
First mortgage bonds due 2044 (Wyoming Electric)	591	22	23	22
First mortgage bonds due 2032	485	33	33	33
First mortgage bonds due 2039	1,657	76	76	76
First mortgage bonds due 2037	613	31	31	31
Other	436	76	304	43
Total	$ 18,478	$3,349	$3,861	$5,617

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs. In addition, the agreements governing our equity units contain restrictions on the payment of cash dividends upon any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the RSNs included in such equity units. As of December 31, 2017, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2017:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2017, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

(7) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2017, we were in compliance with all of these financial covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	December 31, 2017	December 31, 2016
Revolving Credit Facility	$—	$ 96,600
CP Program	211,300	—
Total	$211,300	$ 96,600

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options (subject to consent from the lenders). This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents and subject to receipt of additional commitments from existing or new lenders, to increase total commitments of the facility up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from either S&P or Moody’s for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at December 31, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net amount borrowed under the CP Program during 2017 and our notes outstanding as of December 31, 2017 were $211 million. We did not borrow under the CP Program in 2016 and did not have any notes outstanding as of December 31, 2016. As of December 31, 2017, the weighted average interest rate on CP Program borrowings was 1.76%.

As of December 31, 2017 and 2016, we had outstanding letters of credit totaling approximately $27 million and approximately $36 million, respectively.

Deferred financing costs on the Revolving Credit Facility of $5.4 million are being amortized over its estimated useful life and included in Interest expense on the accompanying Consolidated Statements of Income (Loss).

Debt Covenants

On December 7, 2016, we amended our Revolving Credit Facility and term loan agreements, allowing the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under the amended and restated Revolving Credit Facility and term loan agreements, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to

Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs.

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2017	Covenant Requirement at December 31, 2017
Consolidated Indebtedness to Capitalization Ratio	61 %	Less than 65 %

(8) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to reclamation of coal mining sites in the Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment, retirement of gas pipelines at our Gas Utilities and asbestos at our Electric and Gas Utilities. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following tables present the details of AROs which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2016	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired	Revisions to Prior Estimates (b)	December 31, 2017
Electric Utilities	$ 4,661	$ —	$ (4)	$ 268	$ —	$ 1,362	$ 6,287
Gas Utilities	29,775	—	—	1,142	—	2,321	33,238
Mining	12,440	—	(107)	651	—	(485)	12,499
Total	$ 46,876	$ —	$ (111)	$ 2,061	$ —	$ 3,198	$ 52,024

	December 31, 2015	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired (a)	Revisions to Prior Estimates (b)(c)	December 31, 2016
Electric Utilities	$ 4,462	$ —	$ —	$ 191	$ —	$ 8	$ 4,661
Gas Utilities	136	—	—	791	22,412	6,436	29,775
Mining	18,633	—	(105)	822	—	(6,910)	12,440
Total	$ 23,231	$ —	$ (105)	$ 1,804	$ 22,412	$ (466)	$ 46,876

(a) Represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations. Approximately $22 million was recorded with the purchase price allocation of SourceGas.

(b) The Gas Utilities Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.

(c) The 2016 Mining Revision to Prior Estimates reflects an approximately 33% reduction in equipment costs as promulgated by the State of Wyoming.

We also have legally required AROs related to certain assets within our electric transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a liability for the cost of these obligations cannot be measured at this time.

We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells. These obligations are classified as held for sale at December 31, 2017. See Note 21.

(9) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

Our credit exposure at December 31, 2017 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income (Loss) and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities’ generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements) expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers’ underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2018 through May 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any is reported in Fuel, purchased power and cost of natural gas sold. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Utilities are comprised of both short and long positions. We had the following net long positions as of:

	December 31, 2017		December 31, 2016	
	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	8,330,000	36	14,770,000	48
Natural gas options purchased, net [b]	3,540,000	14	3,020,000	5
Natural gas basis swaps purchased	8,060,000	36	12,250,000	48
Natural gas over-the-counter swaps, net [c]	3,820,000	29	4,622,302	28
Natural gas physical commitments, net [d]	12,826,605	35	21,504,378	10

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(a) Term reflects the maximum forward period hedged.

(b) Volumes purchased as of December 31, 2016 is net of 2,133,000 MMBtus of collar options (call purchase and put sale) transactions.

(c) As of December 31, 2017, 1,650,000 MMBtus of natural gas over-the-counter swaps purchased were designated as cash flow hedges.

(d) Volumes exclude contracts that qualify for normal purchase, normal sales exception.

Based on December 31, 2017 prices, a $0.7 million loss would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Financing Activities

At December 31, 2017, we had no outstanding interest rate swap agreements. In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to fix the Treasury yield component associated with the anticipated issuance of senior notes. These swaps were settled at a loss of $29 million in connection with the issuance of our $400 million of unsecured ten-year senior notes in August 2016. The effective portion of the loss in the amount of $28 million was recognized as a component of AOCI and will be recognized as interest expense over the ten-year life of the $400 million unsecured note issued on August 19, 2016. The ineffective portion of $1.0 million, related to the timing of the debt issuance, was recognized in earnings as a component of interest expense in 2016. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	December 31, 2016 Interest Rate Swaps [a]
Notional	$50,000
Weighted average fixed interest rate	4.94 %
Maximum terms in months	1
Derivative assets, non-current	$—
Derivative liabilities, current	$90
Derivative liabilities, non-current	$—

(a) The $50 million in swaps expired in January 2017. These swaps were designated to borrowings on our Revolving Credit Facility and were priced using three-month LIBOR, matching the floating portion of the related borrowings.

Discontinued Operations

Our Oil and Gas segment was exposed to risks associated with changes in the market prices through the sale and delivery of oil and gas to its customers at competitive prices. Through December 2017, we used exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production to mitigate commodity price risk and preserve cash flows. Hedge accounting was elected on the swaps and futures contracts. These transactions were designated upon inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. As a result of divesting our Oil and Gas segment assets, these activities were discontinued and there were no outstanding derivative agreements as of December 31, 2017. Any cash flows associated with our crude oil and natural gas cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of November 1, 2017. As a result, we reclassified the loss in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of revenues and recognized a pre-tax loss of $0.3 million, which is included in net loss from discontinued operations on the Consolidated Statements of Income (Loss) for the year ended December 31, 2017.

At December 31, 2016, we had outstanding crude oil futures and swap contracts with notional volumes of 108,000 Bbls, crude oil options contracts with notional volumes of 36,000 Bbls and natural gas futures and swap contracts with notional volumes of 2,700,000 MMBtus.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income (Loss) is presented below for the years ended December 31, 2017, 2016 and 2015 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	December 31, 2017			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (2,941)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	913	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(243)	Fuel, purchased power and cost of natural gas sold	(75)
Total impact from cash flow hedges		$ (2,271)		$ (75)

	December 31, 2016			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (3,899)	Interest expense	$ (953)
Commodity derivatives	Net (loss) from discontinued operations	11,019	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(14)	Fuel, purchased power and cost of natural gas sold	—

Total	$ 7,106	$ (953)

	December 31, 2015			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (3,647)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	14,460	Net (loss) from discontinued operations	—
Total		$ 10,813		$ —

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the years ended December 31, 2017, 2016 and 2015. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income (Loss) as incurred.

	December 31, 2017	December 31, 2016	December 31, 2015
	(In thousands)		
Increase (decrease) in fair value:			
Interest rate swaps	$—	$ (31,222)	$ 2,888
Forward commodity contracts	366	(573)	9,782
Recognition of (gains) losses in earnings due to settlements:			
Interest rate swaps	2,941	3,899	3,647
Forward commodity contracts	(670)	(11,005)	(14,460)
Total other comprehensive income (loss) from hedging	$2,637	$ (38,901)	$ 1,857

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended December 31, 2017, 2016 and 2015 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

		2017	2016	2015
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Net (loss) from discontinued operations	$ —	$ (50)	$ —

Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(2,207)	940	—
		$ (2,207)	$ 890	$ —

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our Utilities were $12 million and $8.8 million at December 31, 2017 and 2016, respectively.

(10) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2017 or 2016. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 11. Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 21. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

	As of December 31, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Total	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259
Total	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259

	As of December 31, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	$ 7,469	$ —	$ (3,262)	$ 4,207
Total	—	7,469	—	(3,262)	4,207
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 12,201	$ —	$ (11,144)	$ 1,057
Interest rate swaps	—	90	—	—	90
Total	$ —	$ 12,291	$ —	$ (11,144)	$ 1,147

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis, aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

	Balance Sheet Location	2017 Fair Value of Asset Derivatives	2017 Fair Value of Liability Derivatives	2016 Fair Value of Asset Derivatives	2016 Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Derivative assets - current	$—	$ —	$1,007	$ —
Commodity derivatives	Derivative assets - non-current	—	—	124	—
Commodity derivatives	Current assets held for sale	—	—	154	—
Commodity derivatives	Derivative liabilities - current	—	817	—	—
Commodity derivatives	Other deferred credits and other liabilities	—	67	—	7
Commodity derivatives	Current liabilities held for sale	—	—	—	1,090
Commodity derivatives	Noncurrent liabilities held for sale	—	—	—	231
Interest rate swaps	Derivative liabilities - current	—	—	—	90
Total derivatives designated as hedges		$—	$ 884	$1,285	$ 1,418
Derivatives not designated as hedges:					
Commodity derivatives	Derivative assets - current	$304	$ —	$2,977	$ —
Commodity derivatives	Derivative assets - non-current	—	—	98	—
Commodity derivatives	Derivative liabilities - current	—	1,264	—	1,014
Commodity derivatives	Other deferred credits and other liabilities	—	111	—	36
Commodity derivatives	Current liabilities held for sale	—	—	—	265
Total derivatives not designated as hedges		$304	$ 1,375	$3,075	$ 1,315

Derivatives Offsetting

It is our policy to offset in our Consolidated Balance Sheets contracts which provide for legally enforceable netting of our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at December 31, 2017 and December 31, 2016, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at December 31, 2017 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 1,282	$ (1,282)	$ —
Total derivative assets subject to a master netting agreement or similar arrangement	1,282	(1,282)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	304	—	304
Total derivative assets not subject to a master netting agreement or similar arrangement	304	—	304
Total derivative assets	$ 1,586	$ (1,282)	$ 304

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 11,497	$ (11,497)	$ —

Total derivative liabilities subject to a master netting agreement or similar arrangement	11,497	(11,497	) —
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	2,259	—	2,259
Total derivative liabilities not subject to a master netting agreement or similar arrangement	2,259	—	2,259
Total derivative liabilities	$ 13,756	$ (11,497	) $ 2,259

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2016 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 4,269	$ (3,262)	$ 1,007
Total derivative assets subject to a master netting agreement or similar arrangement	4,269	(3,262)	1,007
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	3,200	—	3,200
Total derivative assets not subject to a master netting agreement or similar arrangement	3,200	—	3,200
Total derivative assets	$ 7,469	$ (3,262)	$ 4,207

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 11,144	$ (11,144)	$ —
Total derivative liabilities subject to a master netting agreement or similar arrangement	11,144	(11,144)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	1,057	—	1,057
Interest Rate Swaps	90	—	90
Total derivative liabilities not subject to a master netting agreement or similar arrangement	1,147	—	1,147
Total derivative liabilities	$ 12,291	$ (11,144)	$ 1,147

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 10, were as follows at December 31 (in thousands):

	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$15,420	$15,420	$13,518	$13,518
Restricted cash and equivalents [a]	$2,820	$2,820	$2,274	$2,274
Notes payable [b]	$211,300	$211,300	$96,600	$96,600
Long-term debt, including current maturities [c] [d]	$3,115,143	$3,350,544	$3,216,932	$3,351,305

(a) Carrying value approximates fair value. Cash and restricted cash are classified in Level 1 in the fair value hierarchy.

(b) Notes payable consist of commercial paper borrowings in 2017 and borrowings on our Revolving Credit Facility in 2016. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(d) Carrying amount of long-term debt is net of deferred financing costs.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, money market mutual funds, and term deposits. As part of our cash management process, excess operating cash is invested in money market mutual funds with our bank. Money market mutual funds are not deposits and are not insured by the U.S. Government, the FDIC, or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable and Long-Term Debt

For additional information on our notes payable and long-term debt, see Note 6 and Note 7.

(12) EQUITY

Equity Units

On November 23, 2015, we issued 5.98 million equity units for total gross proceeds of $299 million. Each Equity Unit has a stated amount of $50 and consists of (i) a forward purchase contract to purchase the Company's common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of RSNs due 2028. The RSNs, a debt instrument, and the forward purchase contracts, an equity instrument, are deemed to be separate instruments as the investor may trade the RSNs separately from the forward purchase contract and may also settle the forward purchase contract separately.

The forward purchase contracts obligate the holders to purchase from the Company on the settlement date, which shall be no later than November 1, 2018, for a price of $50 in cash, the following number of shares of our common stock, subject to anti-dilution adjustments:

- if the "Applicable Market Value" (AMV) of the Company's common stock, which is the average volume-weighted average price of the Company's common stock for the trading days during the 20 consecutive scheduled trading day period ending on the third scheduled trading day immediately preceding the forward purchase contract settlement date, equals or exceeds $47.2938, 1.0572 shares of the Company's common stock per Equity Unit;

- if the AMV is less than $47.2938 but greater than $40.25, a number of shares of the Company's common stock having a value, based on the AMV, equal to $50; and

- if the AMV is less than or equal to $40.25, 1.2422 shares of the Company's common stock.

The RSNs bear interest at a rate of 3.5% per year, payable quarterly, and mature on November 1, 2028. The RSNs will be remarketed in 2018. If this remarketing is successful, the interest rate on the RSNs will be reset, and thereafter interest will be payable semi-annually at the reset rate. If there is no successful remarketing, the interest rate on the RSNs will not be reset, and the holders of the RSNs will have the right to put the RSNs to the Company at a price equal to 100% of the principal amount, and the proceeds of the put right will be deemed to have been applied against the holders' obligation under the forward purchase contracts.

The Company also pays the Equity Unit holders quarterly contract adjustment payments at a rate of 4.25% per year of the stated amount of $50 per Equity Unit, or $2.125 per year up to November 1, 2018. The present value of the future contract adjustment payments, $33 million, was recorded as a reduction of shareholders' equity in the accompanying Consolidated Balance Sheets. Until settlement of the forward purchase contracts, the shares of stock underlying each forward purchase contract are not outstanding. The forward purchase contracts will only be included in the computation of diluted earnings per share to the extent they are dilutive. As of December 31, 2017, the forward purchase contracts were dilutive and therefore included in the computation of diluted earnings per share. Basic earnings per share will not be affected until the forward purchase contracts are settled and the holders thereof become stockholders.

Selected information about our equity units is presented below (in thousands except for percentages):

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt (RSNs)	RSN Interest Rate (annual)	Stock Purchase Contract Rate (annual)	Stock Purchase Contract Liability as of December

						31, 2017
11/23/2015	5,980	$ 290,030	$ 299,000	3.50 %	4.25 %	$ 12,115

At-the-Market Equity Offering Program

On August 4, 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior year program other than the aggregate value increased from $200 million to $300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares under the ATM equity offering program during the twelve months ended December 31, 2017. During the three months ended December 31, 2016, we issued 218,647 common shares for $13 million, net of $0.1 million in commissions under the ATM equity offering program. During the twelve months ended December 31, 2016, we issued an aggregate of 1,968,738 shares of common stock under the ATM equity offering program for $119 million, net of $1.2 million in commissions.

Common Stock Offering

On November 23, 2015, we issued 6.325 million shares of common stock pursuant to a public offering at $40.25 per share. Net proceeds were $246 million. The proceeds from the offering were used to partially fund the purchase of SourceGas, which closed on February 12, 2016.

Equity Compensation Plans

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 979,464 shares available to grant at December 31, 2017.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2017, total unrecognized compensation expense related to non-vested stock awards was approximately $12.0 million and is expected to be recognized over a weighted-average period of 1.9 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income (Loss) was as follows for the years ended December 31 (in thousands):

	2017	2016	2015
Stock-based compensation expense	$7,626	$10,885	$4,076

Stock Options

The Company has not issued any stock options since 2014 and has 96,749 stock options outstanding at December 31, 2017. The amount of stock options granted during the last three years, and related exercise activity are not material to the Company's consolidated financial statements.

Restricted Stock

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and restricted stock units at December 31, 2017, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at beginning of period	295	$ 52.15
Granted	111	60.63
Vested	(128)	51.44
Forfeited	(11)	53.80
Balance at end of period	267	$ 55.94

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended December 31, was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2017	$ 60.63	$ 7,909
2016	$ 53.55	$ 4,602
2015	$ 50.01	$ 6,009

As of December 31, 2017, there was $9.9 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.0 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.5 million at December 31, 2017 would be reclassified as a liability.

Outstanding performance periods at December 31 were as follows (shares in thousands):

Grant Date	Performance Period	Target Grant of Shares	Possible Payout Range of Target Minimum	Maximum
January 1, 2015	January 1, 2015 - December 31, 2017	43	0%	200%
January 1, 2016	January 1, 2016 - December 31, 2018	53	0%	200%
January 1, 2017	January 1, 2017 - December 31, 2019	51	0%	200%

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion Shares (in thousands)	Weighted-Average Grant Date Fair Value (a)	Liability Portion Shares (in thousands)	Weighted-Average Fair Value at December 31, 2017
Performance Shares balance at beginning of period	71	$ 52.29	71	
Granted	26	63.52	26	
Forfeited	(1)	55.01	(1)	
Vested	(22)	55.18	(22)	
Performance Shares balance at end of period	74	$ 55.31	74	$ 22.31

(a) The grant date fair values for the performance shares granted in 2017, 2016 and 2015 were determined by Monte Carlo simulation using a blended volatility of 23%, 24% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

The weighted-average grant-date fair value of performance share awards granted was as follows in the years ended:

Weighted Average Grant Date Fair Value

December 31, 2017 $ 63.52
December 31, 2016 $ 47.76
December 31, 2015 $ 54.92

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Shares Issued	Cash Paid	Total Intrinsic Value
January 1, 2014 to December 31, 2016	2017	—	$—	$ —
January 1, 2013 to December 31, 2015	2016	—	$—	$ —
January 1, 2012 to December 31, 2014	2015	69	$3,657	$ 7,314

On January 30, 2018, the Compensation Committee of our Board of Directors determined that the Company's performance criteria for the January 1, 2015 through December 31, 2017 performance period was not met. As a result, there will be no payout for this period.

As of December 31, 2017, there was $2.1 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.6 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued new shares during 2017 and 2016.

A summary of the DRSPP for the years ended December 31 is as follows (shares in thousands):

	2017	2016
Shares Issued	48	51
Weighted Average Price	$65.40	$58.24
Unissued Shares Available	308	356

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

Sale of Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third-party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes.

ASC 810 requires the accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Net income available for common stock for the years ended December 31, 2017 and December 31, 2016 was reduced by $14 million and $9.6 million, respectively, attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of December 31:

	2017	2016
	(in thousands)	
Assets		
Current assets	$14,837	$12,627
Property, plant and equipment of variable interest entities, net	$208,595	$218,798
Liabilities		
Current liabilities	$4,565	$4,342

(13) REGULATORY MATTERS

Electric Utilities Rate Activity

South Dakota Electric Common Use System (CUS): The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2018 the annual revenue requirement increased by $3.3 million and included estimated weighted average capital additions of $45 million for 2017 and 2018. The annual transmission revenue requirement has a true up mechanism that is posted in June of each year.

South Dakota Electric Settlement: On June 16, 2017, South Dakota Electric received approval from the SDPUC on a settlement reached with the SDPUC staff agreeing to a 6-year moratorium period effective July 1, 2017. As part of this agreement, South Dakota Electric will not increase base rates, absent an extraordinary event. The moratorium period also includes suspension of both the Transmission Facility Adjustment and the Environmental Improvement Adjustment, and a $1.0 million increase to the annual power marketing margin guarantee during this period. Additionally, existing regulatory asset balances of approximately $13 million related to decommissioning and Winter Storm Atlas are being amortized over the moratorium period. These balances were previously being amortized over a 10-year period ending September 30, 2024. The vegetation management regulatory asset of $14 million, previously unamortized, is also being amortized over the moratorium period. The change in amortization periods for these costs increased annual amortization expense by approximately $2.7 million. The June 16, 2017 settlement had no impact to base rates.

Colorado Electric Rate Case filing: On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine and normal increases in operating expenses. This increase is in addition to approximately $5.9 million in annualized revenue being recovered under the Clean Air Clean Jobs Act construction financing rider. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.

On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision which reduced our proposed $8.9 million annual revenue increase to $1.2 million. Concurrent with this application, we filed a motion for a Commissioner to recuse themselves from continuing to participate in any further proceedings in the rate review. On October 4, 2017, the Company filed an Opening Brief. The Company filed a Reply Brief on November 22, 2017. The matter is pending.

We believe the CPUC made errors in their December decision by demonstrating bias, making decisions not supported by evidence, making findings inconsistent with cost-recovery provisions of the Colorado Clean Air-Clean Jobs Act and the

Commission's own prior decisions, and treating Colorado Electric differently than other regulated utilities in Colorado have been treated in similar situations.

Gas Utilities Rate Activity

On December 15, 2017, Arkansas Gas filed a rate review application with the APSC requesting an annual increase in revenue of approximately $30 million. The annual increase is based on a return on equity of 10.2% and a capital structure of 45.3% debt and 54.7% equity. This rate review was driven by approximately $160 million of investments made since 2016 to replace, upgrade and maintain Arkansas Gas' approximately 5,500 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in the fourth quarter of 2018. We are reviewing the impact of tax reform as it applies to the filing.

On November 17, 2017, Wyoming Gas filed a rate review application with the WPSC requesting an annual increase in revenue of approximately $1.4 million for natural gas system improvements supporting its Northwest Wyoming customers. The annual increase is based on a return on equity of 10.2% and a capital structure of 46.0% debt and 54.0% equity. This rate review was driven by approximately $6 million of investments made since 2015 to replace, upgrade and maintain approximately 620 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in mid-2018. We are reviewing the impact of tax reform as it applies to the filing.

On November 1, 2017, RMNG filed a rate review with the CPUC requesting recovery of $3.1 million, which includes $0.2 million of new revenue related to system safety and integrity expenditures on projects for the period of 2014 through 2018. This SSIR request was approved by the CPUC in December 2017, and is effective January 1, 2018.

On October 3, 2017, RMNG filed a rate review application with the CPUC requesting an annual increase in revenue of $2.2 million and an extension of the SSIR to recover costs from 2018 through 2022. The annual increase is based on a return on equity of 12.25% and a capital structure of 53.37% debt and 46.63% equity. This rate review was driven by the impending expiration of the SSIR on May 31, 2018; this application requests a continuation of the SSIR through 2022. We are reviewing the impact of tax reform as it applies to the filing.

Monthly, Arkansas Gas files for recovery of projects related to the replacement of eligible mains (MRP) and projects for the relocation of certain at risk meters (ARMRP). On February 1, 2018, Arkansas Gas requested MRP revenue of $2.8 million and ARMPR revenue of $0.5 million for assets placed in service between April 1, 2016 and December 31, 2017. Pursuant to the Arkansas Gas Tariff, the filed rates are effective the date filed.

Annually, Arkansas Gas files for recovery of Stockton Storage revenue requirement through the Stockton Storage Acquisition Rates regulatory mechanism. On November 16, 2017 Arkansas Gas filed a request for recovery of $3.3 million for the revenue requirement year ended September 30, 2017. Rates were effective January 1, 2017.

On October 2, 2017, Nebraska Gas Distribution filed with the NPSC requesting recovery of $6.8 million, which includes $0.3 million of increased annual revenue related to system safety and integrity expenditures on projects for the period of 2012 through 2017. This SSIR tariff was approved by the NPSC in January 2018, and went into effect on February 1, 2018.

In February 2016, Arkansas Gas implemented new base rates resulting in a revenue increase of $8.0 million. The APSC modified a stipulation reached between the APSC Staff and all intervenors except the Attorney General and Arkansas Gas in its order issued on January 28, 2016. The modified stipulation revised the capital structure to 52% debt and 48% equity and also limited recovery of portions of cost related to incentive compensation.

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(14) OPERATING LEASES

We have entered into lease agreements for vehicles, equipment and office facilities. Rental expense incurred under these operating leases, including month to month leases, for the years ended December 31 was as follows (in thousands):

	2017	2016	2015
Rent expense	$10,325	$9,568	$7,177

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2018	$5,030
2019	$3,840
2020	$1,957
2021	$918
2022	$808
Thereafter	$3,085

(15) INCOME TAXES

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the book and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, cash flows or financial position. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA.

In addition, as allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Company has recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation, for which the impacts could not be finalized upon issuance of the Company's financial statements but reasonable estimates could be determined. The provisional amounts may change as the Company finalizes the analysis and computations, and such changes could be material to the Company's future results of operations, cash flows or financial position.

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2017	2016	2015
Current:			
Federal	$(6,193)	$(21,806)	$2,624
State	(1,432)	(1,797)	1,329
	(7,625)	(23,603)	3,953
Deferred:			
Federal	76,567	78,997	71,332
State	4,470	3,759	3,485

Tax credit amortization	(45)	(52)	(113)
	80,992	82,704	74,704
	$73,367	$59,101	$78,657

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Included in discontinued operations is a tax benefit of $8.4 million, $49 million and $101 million for 2017, 2016 and 2015, respectively.

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2017	2016
Deferred tax assets:		
Regulatory liabilities	$90,742	$58,200
Employee benefits	18,724	28,873
Federal net operating loss	155,276	252,780
Other deferred tax assets[(a)]	74,561	83,675
Less: Valuation allowance	(9,121)	(9,263)
Total deferred tax assets	330,182	414,265
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences[(b)]	(510,774)	(782,674)
Regulatory assets	(26,245)	(49,471)
Goodwill	(46,392)	(60,544)
State deferred tax liability	(58,930)	(50,258)
Deferred costs	(16,063)	(18,551)
Other deferred tax liabilities	(8,298)	(14,702)
Total deferred tax liabilities	(666,702)	(976,200)
Net deferred tax liability	$(336,520)	$(561,935)

(a) Other deferred tax assets consist primarily of alternative minimum tax credit and federal research and development credits. No single item exceeds 5% of the total net deferred tax liability.

(b) The net deferred tax liabilities were revalued for the change in federal tax rate to 21% under the TCJA. The revaluation resulted in a reduction to net deferred tax liabilities of approximately $309 million. Due to the regulatory construct, approximately $301 million of the revaluation was reclassified to a regulatory liability.

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2017	2016	2015
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax (net of federal tax effect)	0.9	1.2	1.5
Percentage depletion	(0.6)	(0.8)	(0.7)
Non-controlling interest [(a)]	(1.8)	(1.6)	—
Equity AFUDC	(0.2)	(0.5)	(0.1)
Tax credits	(1.7)	(0.4)	(0.1)
Transaction costs	—	0.5	—
Accounting for uncertain tax positions adjustment	(0.2)	(2.7)	0.8
Flow-through adjustments [(b)]	(1.1)	(2.1)	(1.0)
Other tax differences	(0.9)	0.1	0.3
IRC 172(f) carryback claim	(0.7)	—	—
Tax Cuts & Jobs Act corporate rate reduction [(c)]	(2.7)	—	—
	26.0 %	28.7 %	35.7 %

(a) The effective tax rate reflects the income attributable to the noncontrolling interest in Black Hills Colorado IPP for which a tax provision was not recorded.

(b) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs and certain indirect costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.

(c) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21% effective January 1, 2018. The 2017 effective tax rate reduction reflects the revaluation of deferred income taxes associated with non-regulated operations required by the change.

At December 31, 2017, we have federal and state NOL carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates
Federal Net Operating Loss Carryforward	$739,184	2019 to 2037
State Net Operating Loss Carryforward	$688,335	2017 to 2038

As of December 31, 2017, we had a $1.3 million valuation allowance against the state NOL carryforwards. Our 2017 analysis of the ability to utilize such NOLs resulted in a slight increase in the valuation allowance of approximately $0.4 million, which resulted in an increase to tax expense. The valuation allowance adjustment was primarily attributable to a projected decrease in state taxable income for years beyond 2017. This projected decrease impacted the utilization of NOL carryforward in those states where the carryforward period is significantly shorter than the federal carryforward period of 20 years. In certain states, the carryforward period is limited to 5 years. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	Changes in Uncertain Tax Positions
Beginning balance at January 1, 2015	$ 32,192
Additions for prior year tax positions	3,285
Reductions for prior year tax positions	(3,491)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2015	31,986
Additions for prior year tax positions	2,423
Reductions for prior year tax positions	(19,174)
Additions for current year tax positions	—
Settlements	(11,643)
Ending balance at December 31, 2016	3,592
Additions for prior year tax positions	358
Reductions for prior year tax positions	(5,713)
Additions for current year tax positions	5,026
Settlements	—
Ending balance at December 31, 2017	$ 3,263

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.2 million.

We recognized no interest expense for the years ended December 31, 2017 and December 31, 2016, and approximately $1.6 million for the year ended December 31, 2015. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2017 and December 31, 2016.

Black Hills Corporation and its subsidiaries are currently under examination by the IRS for the 2010 to 2012 tax years. A 30-day Letter was received in second quarter 2016 along with a Revenue Agent's Report from the IRS in regard to the audit of the 2010 to 2012 tax years disallowing certain R&D credits and deductions claimed with respect to certain costs and projects. In response to the 30-day Letter, a protest was timely filed with IRS Appeals in the second quarter of 2016 and a final settlement at IRS Appeals is expected to be reached in 2018. Black Hills Gas, Inc. and subsidiaries, which files a separate consolidated tax return from Black Hills Corporation and subsidiaries, is under examination by the IRS for 2014.

We had deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes attributable to the like-kind exchange effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. The IRS had challenged our position with respect to the like-kind exchange. In the first quarter of 2016, we reached a settlement agreement in principle with IRS Appeals related to both the like-kind exchange transaction in addition to the R&D credits and deductions issues. In 2016, the settlement resulted in a reduction to the liability for unrecognized tax benefits of approximately $29 million excluding interest. Approximately $17 million of the reduction was to restore accumulated deferred income taxes and the remaining portion of approximately $12 million was reclassified to current taxes payable.

As of December 31, 2017, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2018.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2017, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards		Expiration Year
Investment tax credit	$20,285	2023 to 2036
Research and development	$179	No expiration

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As of December 31, 2017, we had a $7.8 million valuation allowance against the state tax credit carryforwards. The re-evaluation of our ability to utilize such credits resulted in an increase of the valuation allowance of approximately $1.2 million of which approximately $0.6 million resulted in an increase to tax expense. The remaining $0.6 million increase is attributable to our regulated business and is being accounted for under the deferral method whereby the credits are amortized to tax expense over the estimated useful life of the underlying asset that generated the credit. The valuation allowance adjustment was primarily attributable to the impact of lower projected apportionment factors resulting in decreased state taxable income in years beyond 2017. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(16) OTHER COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Consolidated Statements of Income (Loss) for the period, net of tax (in thousands):

	Location on the Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI December 31, 2017	Amount Reclassified from AOCI December 31, 2016
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$(2,941)	$(3,899)
Commodity contracts	(Loss) from discontinued operations	913	11,019
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(243)	(14)
		(2,271)	7,106
Income tax	Income tax benefit (expense)	875	(2,702)
Total reclassification adjustments related to cash flow hedges, net of tax		$(1,396)	$4,404
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$168	$194
Prior service cost	(Loss) from discontinued operations	29	27
Actuarial gain (loss)	Operations and maintenance	(1,599)	(1,881)
Actuarial gain (loss)	(Loss) from discontinued operations	(58)	(97)
		(1,460)	(1,757)
Income tax	Income tax benefit (expense)	(516)	533
Total reclassification adjustments related to defined benefit plans, net of tax		$(1,976)	$(1,224)
Total reclassifications		$(3,372)	$3,180

Balances by classification included within AOCI, net of tax on the accompanying Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2016	$(18,109)	$ (233)	$(16,541)	$(34,883)
Other comprehensive income (loss) before reclassifications	—	231	(1,890)	(1,659)
Amounts reclassified from AOCI	1,912	(516)	944	2,340
Reclassification of certain tax effects from AOCI	(3,384)	—	(3,616)	(7,000)
As of December 31, 2017	$(19,581)	$ (518)	$(21,103)	$(41,202)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2015	$(341)	$ 7,066	$(15,780)	$(9,055)
Other comprehensive income (loss) before reclassifications	(20,302)	(361)	(1,985)	(22,648)
Amounts reclassified from AOCI	2,534	(6,938)	1,224	(3,180)
As of December 31, 2016	$(18,109)	$ (233)	$(16,541)	$(34,883)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2017	2016	2015
	(in thousands)		
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$28,191	$27,034	$25,039
Increase (decrease) in capitalized assets associated with asset retirement obligations	$3,198	$8,577	$(1,498)
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$(132,428)	$(113,627)	$(78,744)
Income taxes (paid) refunded	$1,775	$(1,156)	$(1,202)

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(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor 401(k) retirement savings plans (the 401(k) Plans). Participants in the 401(k) Plans may elect to invest a portion of their eligible compensation in the 401(k) Plans up to the maximum amounts established by the IRS. The 401(k) Plans provide employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plans provide either a Company Matching Contribution or a Non-Elective Safe Harbor Contribution for all eligible participants, depending upon the Plan in which the employee participates. Certain eligible participants receive a Company Retirement Contribution based on the participant’s age and years of service or a Company Discretionary Contribution, depending upon the pension plan in which the employee participates. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

The SourceGas Retirement Savings Plan was merged into the Black Hills Corporation Retirement Savings Plan effective December 31, 2017. The plan design of the Black Hills Corporation 401(k) Plan will apply to all employees as of January 1, 2018.

Defined Benefit Pension Plan (Pension Plan)

At December 31, 2016 our three previous defined benefit pension plans consisting of the Black Hills Corporation Pension Plan, the Black Hills Utility Holding, Inc. Pension Plan and the SourceGas Retirement Plan were merged into one single plan, the Black Hills Retirement Plan (Pension Plan). The Pension Plan covers certain eligible employees of the Company. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. Due to the plan merger on December 31, 2016, reporting beginning in 2017 no longer represents an undivided interest in the Master Trust. Our Board of Directors has approved the Pension Plan’s investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan’s beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan’s benefit payment obligations. The Pension Plan’s assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2017, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 37% to 45% equity securities and 55% to 63% fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets was based on the targeted asset allocation range of 15% to 25% equity securities and 75% to 85% fixed-income securities and the expected rate of return from these asset categories.

The expected long-term rate of return for investments was 6.25% and 6.75% for the Pension Plan 2017 and 2016 plan years, respectively. Our Pension Plan is funded in compliance with the federal government’s funding requirements.

Plan Assets

The percentages of total plan asset by investment category for our Pension Plan at December 31 were as follows:

	2017	2016
Equity	26%	28%
Real estate	4	5
Fixed income	63	57
Cash	1	2
Hedge funds	6	8
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plans

BHC sponsors retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans for participating business units are pre-funded via VEBAs. Pre-65 retirees as well as a grandfathered group of post-65 Cheyenne Light, Fuel and Power (“CLFP”) retirees and a grandfathered group of post-65 former SourceGas employees who retired prior to January 1, 2017 receive their retiree medical benefits through the Black Hills self-insured retiree medical plans.

Healthcare coverage for Medicare-eligible BHC and Black Hills Utility Holdings retirees is provided through an individual market healthcare exchange. Medicare-eligible SourceGas employees who retired after December 31, 2016 also receive retiree medical coverage through an individual market healthcare exchange.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Utility Holding and SourceGas Postretirement - AWG Plans provide for partial pre-funding via VEBAs and a Grantor Trust. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Kansas and Iowa. We do not pre-fund the Healthcare Plans for those employees outside Arkansas, Kansas and Iowa.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Healthcare benefits include company and participant paid premiums. Contributions for the years ended December 31 were as follows (in thousands):

	2017	2016
Defined Contribution Plan		
Company retirement contribution	$10,223	$9,632
Matching contributions	$9,811	$9,645

	2017	2016
Defined Benefit Plans		
Defined Benefit Pension Plan	$27,700	$14,200
Non-Pension Defined Benefit Postretirement Healthcare Plans	$4,332	$4,965
Supplemental Non-Qualified Defined Benefit Plans	$3,217	$1,565

While we do not have required contributions, we expect to make approximately $13 million in contributions to our Pension Plan in 2018.

Fair Value Measurements

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Pension Plan	December 31, 2017					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
AXA Equitable General Fixed Income	$—	$1,280	$ —	$ 1,280	$—	$ 1,280
Common Collective Trust - Cash and Cash Equivalents	—	2,184	—	2,184	—	2,184
Common Collective Trust - Equity	—	109,496	—	109,496	—	109,496
Common Collective Trust - Fixed Income	—	262,329	—	262,329	—	262,329
Common Collective Trust - Real Estate	—	1,728	—	1,728	15,701	17,429
Hedge Funds	—	—	—	—	23,625	23,625
Total investments measured at fair value	$—	$377,017	$ —	$ 377,017	$39,326	$ 416,343

Pension Plan	December 31, 2016					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
AXA Equitable General Fixed Income	$—	$1,325	$ —	$ 1,325	$—	$ 1,325
Common Collective Trust - Cash and Cash Equivalents	—	5,307	—	5,307	—	5,307
Common Collective Trust - Equity	—	101,020	—	101,020	—	101,020
Common Collective Trust - Fixed Income	—	209,815	—	209,815	—	209,815
Common Collective Trust - Real Estate	—	2,349	—	2,349	15,563	17,912
Hedge Funds	—	—	—	—	29,316	29,316
Total investments measured at fair value	$—	$319,816	$ —	$ 319,816	$44,879	$ 364,695

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(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan's benefit obligations and fair value of plan assets above.

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2017					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
Cash and Cash Equivalents	$4,671	$—	$ —	$ 4,671	$ —	$ 4,671
Equity Securities	1,374	—	—	1,374	—	1,374
Intermediate-term Bond	—	2,576	—	2,576	—	2,576
Total investments measured at fair value	$6,045	$2,576	$ —	$ 8,621	$ —	$ 8,621

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Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2016					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
Cash and Cash Equivalents	$111	$—	—	$ 111	—	$ 111
Equity Securities	1,154	—	—	$ 1,154	—	1,154
Registered Investment Company Trust - Money Market Mutual Fund	—	4,732	—	$ 4,732	—	4,732
Intermediate-term Bond	—	2,473	—	$ 2,473	—	2,473
Total investments measured at fair value	$1,265	$7,205	$ —	$ 8,470	$ —	$ 8,470

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plans' benefit obligations and fair value of plan assets above.

Additional information about assets of the benefit plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

Cash and Cash Equivalents: This represents an investment in Invesco Treasury Portfolio, which is a short-term investment trust, as well as an investment in Northern Institutional Government Assets Portfolio, which is described as a government money market fund. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Equity Securities: These represent investments in a combination of equity positions for mainly large cap core allocation and Exchange Trade Funds (ETFs) for diversification into the other sectors of the economy. ETFs are a basket of securities traded like individual stocks on the exchange. Value of equity securities held at year end are based on published market quotations of active markets. The ETF funds can be redeemed on a daily basis at their market price and have no redemption restrictions. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Intermediate-term bond: This is comprised of a diversified pool of high quality, individual municipal bonds. Pricing is evaluated using multi-dimensional relational models, as well as a series of matrices using Standard Inputs, including Municipal Securities Rule Making Board (MSRB) reported trades and material event notices, plus Municipal Market Data (MMD) benchmark yields and new issue data. As the models use observable inputs and standard data, the investments are categorized as Level 2.

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates of loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

Common Collective Trust-Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal

Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Common Collective Trust-Real Estate Fund: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter, with a 65 day notice and are limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the Consolidated Balance Sheets, components of the net periodic expense and elements of AOCI (in thousands):

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2017	2016	2017	2016	2017	2016
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$440,179	$356,575	$43,869	$40,219	$68,023	$48,077
Transfer from SourceGas Acquisition	—	75,254	—	—	—	15,091
Service cost	7,034	7,619	2,937	2,099	2,300	1,757
Interest cost	15,520	15,743	1,276	1,257	2,141	1,942
Actuarial (gain) loss [(a)]	36,661	7,001	247	2,049	(396)	2,808
Amendments	—	—	—	—	265	2,203
Benefits paid	(24,669)	(22,013)	(3,217)	(1,755)	(4,332)	(4,965)
Plan participants' contributions	—	—	—	—	1,338	1,110
Projected benefit obligation at end of year	$474,725	$440,179	$45,112	$43,869	$69,339	$68,023

(a) Increase from 2016 is primarily the result of a decrease in the discount rate.

Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans [(a)]	
As of December 31,	2017	2016	2017	2016	2017	2016
Change in fair value of plan assets:						
Beginning fair value of plan assets	$364,695	$288,622	$ —	$ —	$8,470	$4,681
Transfer from SourceGas Acquisition	—	53,067	—	—	—	3,340
Investment income (loss)	48,617	30,819	—	—	120	256
Employer contributions	27,700	14,200	3,217	1,755	3,025	4,048
Retiree contributions	—	—	—	—	1,338	1,110
Benefits paid	(24,669)	(22,013)	(3,217)	(1,755)	(4,332)	(4,965)
Ending fair value of plan assets	$416,343	$364,695	$ —	$ —	$8,621	$8,470

(a) Assets of VEBAs and Grantor Trust.

The funded status of the plans and the amounts recognized in the Consolidated Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Regulatory assets	$72,756	$66,640	$—	$—	$11,507	$11,401
Current liabilities	$—	$—	$1,372	$1,583	$4,423	$4,360
Non-current assets	$—	$—	$—	$—	$69	$21
Non-current liabilities	$58,381	$75,484	$43,739	$42,286	$56,365	$55,214
Regulatory liabilities	$5,232	$5,195	$—	$—	$3,334	$3,419

Accumulated Benefit Obligation

As of December 31 (in thousands)	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Accumulated Benefit Obligation [a]	$450,394	$416,786	$41,243	$32,090	$69,339	$68,023

(a) The Defined Benefit Pension Plan Accumulated Benefit Obligation for 2017 and 2016 represents the obligation for the merged Black Hills Retirement Plan. The Non-pension Defined Benefit Retirement Healthcare Plans Accumulated Benefit Obligation for 2017 and 2016 represents that obligation for the five postretirement plans maintained by BHC.

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Service cost	$7,034	$7,619	$6,093	$1,546	$1,335	$1,380	$2,300	$1,757	$1,808
Interest cost	15,520	15,743	15,522	1,276	1,257	1,455	2,141	1,942	1,801
Expected return on assets	(24,517)	(23,062)	(19,470)	—	—	—	(315)	(279)	(131)
Net amortization of prior service cost	58	58	58	2	2	2	(411)	(428)	(428)
Recognized net actuarial loss (gain)	4,007	7,173	11,037	1,001	829	1,081	499	335	408
Settlement expense[a]	—	10	—	—	—	—	—	—	—
Net periodic expense	$2,102	$7,541	$13,240	$3,825	$3,423	$3,918	$4,214	$3,327	$3,458

(a) Settlement expense is the result of lump-sum payments on the SourceGas Retirement Plan in excess of interest and service costs for the year.

AOCI

For defined benefit plans, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Net (gain) loss	$10,056	$8,472	$6,639	$7,132	$1,309	$1,595
Prior service cost (gain)	21	31	4	5	(542)	(694)
Reclassification of certain tax effects from AOCI	2,087	—	1,371	—	158	—
Total AOCI	$12,164	$8,503	$8,014	$7,137	$925	$901

The amounts in AOCI, Regulatory assets or Regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2018 are as follows (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plans
Net loss	$ 5,610	$ 650	$ 141
Prior service cost (credit)	38	1	(258)
Total net periodic benefit cost expected to be recognized during calendar year 2018	$ 5,648	$ 651	$ (117)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine benefit obligations:	2017	2016	2015	2017	2016	2015	2017	2016	2015
Discount rate	3.71 %	4.27 %	4.58 %	3.56 %	4.02 %	4.28 %	3.60 %	3.96 %	4.17 %
Rate of increase in compensation levels	3.43 %	3.47 %	3.51 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2017	2016	2015	2017	2016	2015	2017	2016	2015
Discount rate [(a)]	4.27 %	4.50 %	4.19 %	4.02 %	4.28 %	4.19 %	4.05 %	4.18 %	3.82 %
Expected long-term rate of return on assets [(b)]	6.75 %	6.87 %	6.75 %	N/A	N/A	N/A	3.88 %	3.83 %	3.00 %
Rate of increase in compensation levels	3.47 %	3.42 %	3.76 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

(a) The estimated discount rate for the merged Black Hills Retirement Plan is 3.71% for the calculation of the 2018 net periodic pension costs.

(b) The expected rate of return on plan assets is 6.25% for the calculation of the 2018 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	2017	2016 [(a)]
Trend Rate - Medical		
Pre-65 for next year - All Plans	7.00%	6.10%
Pre-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2027	2024
Post-65 for next year - All Plans	5.00%	5.10%
Post-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2026	2023

(a) The 2016 Medical Trend Rates include the two additional non-pension defined benefit postretirement plans from SourceGas.

We do not pre-fund our supplemental plans or three of the five healthcare plans. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2017 Accumulated Postretirement Benefit Obligation	Impact on 2018 Service and Interest Cost
Increase 1%	$ 2,968	$ 148
Decrease 1%	$ (2,534)	$ (126)

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. See “Pension and Postretirement Benefit Obligations” within our Critical Accounting Policies in Item 7 on Form 10-K for additional details.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-Pension Defined Benefit Postretirement Healthcare Plans
2018	$21,495	$ 1,372	$ 5,633
2019	$23,238	$ 1,617	$ 6,231
2020	$27,203	$ 1,558	$ 6,328
2021	$26,990	$ 1,773	$ 6,072
2022	$27,427	$ 1,872	$ 5,920
2023-2027	$154,771	$ 11,304	$ 26,365

(19) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts with non-affiliated third-parties:

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- South Dakota Electric's PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.

- South Dakota Electric's firm point-to-point transmission service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- Wyoming Electric's PPA with Duke Energy's Happy Jack wind site, expiring September 3, 2028, provides up to 30 MW of wind energy from Happy Jack to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility output to South Dakota Electric.

- Wyoming Electric's PPA with Duke Energy's Silver Sage wind site, expiring September 30, 2029, provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of energy from Silver Sage to South Dakota Electric.

- Colorado Electric's REPA with AltaGas expiring October 16, 2037, provides up to 14.5 MW of wind energy from the Busch Ranch Wind Farm in which Colorado Electric owns a 50% undivided ownership interest.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2017	2016	2015
PPA with PacifiCorp	$13,218	$12,221	$13,990
Transmission services agreement with PacifiCorp	$1,671	$1,428	$1,213
PPA with Happy Jack	$3,846	$3,836	$3,155
PPA with Silver Sage	$4,934	$4,949	$4,107
Busch Ranch Wind Farm	$1,966	$2,071	$1,734
PPAs with Cargill [(a)]	$—	$10,995	$16,112

(a) PPAs with Cargill expired on December 31, 2016.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation and storage capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2044.

Purchase Commitments

We maintain natural gas supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated baseload gas volumes are established prior to the beginning of the month under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month based on requirements in accordance with the terms of the individual contract.

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2017, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

	CIG Rockies	NNG-Ventura	NWPL-Wyoming	EP-San Juan Basin	Other
2018	5,784,827	3,759,500	1,298,970	278,600	30,562
2019	5,776,125	3,704,300	786,470	287,000	—
2020	75,075	3,660,000	—	206,600	—
2021	—	3,650,000	—	—	—
2022	—	1,810,000	—	—	—

Purchases under these contracts totaled $65 million, $31 million and $48 million for 2017, 2016 and 2015, respectively.

The following is a schedule of unconditional purchase obligations required under the power purchase, transmission services, coal and natural gas transportation and storage agreements (in thousands):

	Power Purchase Agreements	Transportation, storage and coal agreements
2018	$ 28,041	$ 121,485
2019	$ 6,837	$ 122,351
2020	$ 6,837	$ 117,332
2021	$ 6,203	$ 107,918
2022	$ 6,203	$ 87,393
Thereafter	$ 6,204	$ 202,831

Future Purchase Agreement - Related Party

Wyoming Electric’s PPA for 60 MW of capacity and energy from Black Hills Wyoming’s Wygen I generating facility expiring on December 31, 2022, includes an option for Wyoming Electric to purchase Black Hills Wyoming’s ownership in the Wygen I facility. The purchase price related to the option is $2.6 million per MW which is the equivalent per MW of the pre-construction estimated cost of the Wygen III plant, which was completed in April 2010. This option purchase price is adjusted for capital additions and reduced by an amount equal to annual depreciation based on a 35-year life starting January 1, 2009. The purchase option would be subject to WPSC and FERC approval in order to obtain regulatory treatment.

Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- South Dakota Electric has an agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which expires September 3, 2019, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- South Dakota Electric has a PPA with MEAN expiring May 31, 2023. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

- South Dakota Electric has an agreement from January 1, 2017 through December 31, 2021 to provide 50 MW of energy to Cargill (assigned to Macquarie on January 3, 2018) during heavy and light load timing intervals.

Related Party Lease

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease whereby Colorado Electric, as lessee, has included the combined-cycle turbines as property, plant and equipment along with the related lease obligation and Black Hills Colorado IPP, as lessor, has recorded a lease receivable. Segment revenue and expenses associated with the PPA have been impacted by the lease accounting. The effect of the lease accounting is eliminated in corporate consolidations.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Wyoming Electric for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric's Letter of Credit attached to these bonds.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. Laws and regulations can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years following the closure certification date.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years following the closure certification date.

Our W.N. Clark plant, which has been retired, previously delivered coal ash to a permitted, privately-owned landfill. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond of $4.1 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its land lease for Busch Ranch, Colorado Electric is required to reclaim all land where it has placed wind turbines. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 8 for additional information.

Manufactured Gas Processing

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.5 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $1.0 million regulatory asset for manufactured gas processing sites; see Note 1. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

As of December 31, 2017, our estimated liabilities for Iowa's MGP sites currently range from approximately $2.6 million to $6.1 million for which we had $2.6 million accrued for remediation of sites as of December 31, 2017 included in Other deferred credits and other liabilities on our Consolidated Balance Sheets.

For additional information on environmental matters, see Item 1 in this Annual Report on Form 10-K.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

(20) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds and a contract performance guarantee.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2017	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 58,221	Ongoing
	$ 58,221	

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(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

(21) DISCONTINUED OPERATIONS

Results of operations for discontinued operations have been classified as Income from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. Current assets, noncurrent assets, current liabilities and non-current liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as “Current assets held for sale,” “Noncurrent assets held for sale,” “Current liabilities held for sale,” and “Noncurrent liabilities held for sale”, respectively. Prior periods relating to our discontinued operations have also been reclassified to reflect consistency within our consolidated financial statements.

Oil and Gas Segment

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90% of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018.

We are in the process of divesting our Oil and Gas segment; therefore, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The market approach was based on our recent fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made.

At December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required an after-tax write down of $13 million. There were no adjustments made to the fair value of our held for sale liabilities.

Total assets and liabilities of BHEP at December 31, 2017 have been classified as Current assets held for sale and Current liabilities held for sale on the accompanying Consolidated Balance Sheets due to the expected final disposals occurring by mid-year 2018. Held for sale assets and liabilities at December 31, 2016 are classified as current and non-current.

(in thousands)	As of December 31, 2017	December 31, 2016
Other current assets	$10,360	$11,401
Derivative assets, current and noncurrent	—	153
Deferred income tax assets, noncurrent, net	16,966	26,329
Property, plant and equipment, net	56,916	82,812
Other current liabilities	(18,966)	(9,834)
Derivative liabilities, current and noncurrent	—	(1,586)
Other noncurrent liabilities	(22,808)	(22,803)
Net assets	$42,468	$86,472

At December 31, 2017 and 2016, the Oil and Gas segment’s net deferred tax assets were primarily comprised of basis differences on oil and gas properties.

BHEP’s accrued liabilities at December 31, 2017 and 2016 consisted primarily of accrued royalties, payroll and property taxes. Other liabilities at December 31, 2017 and 2016 consisted primarily of ARO obligations relating to plugging and abandonment of oil and gas wells.

Operating results of the Oil and Gas segment included in Discontinued operations on the accompanying Consolidated Statements of Income were as follows (in thousands):

	For the Years Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
Revenue	$25,382	$ 34,058	$ 43,283
Operations and maintenance	22,872	27,187	35,461
Depreciation, depletion and amortization	7,521	13,510	28,838
Impairment of long-lived assets	20,385	106,957	249,608
Total operating expenses	50,778	147,654	313,907
Operating (loss)	(25,396)	(113,596)	(270,624)
Interest income (expense), net	181	698	931
Other income (expense), net	(297)	110	(378)
Impairment of equity investments	—	—	(4,405)
Income tax benefit (expense)	8,413	48,626	100,817
(Loss) from discontinued operations	$(17,099)	$ (64,162)	$ (173,659)

Full Cost Accounting

Historically, we used the full cost method of accounting for oil and gas production activities. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are typically treated as adjustments to the cost of the properties with no gain or loss recognized.

Costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized.

Under the full cost method, net capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC, plus the lower of cost or market value of unevaluated properties. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost “ceiling” at period end, a permanent non-cash write-down would be charged to earnings in that period.

Impairment of long-lived assets

As discussed above, at December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required a write down of $20 million. There were no adjustments made to the fair value of our held for sale liabilities.

As a result of continued low commodity prices throughout 2016, we recorded non-cash ceiling test impairments of oil and gas assets totaling approximately $92 million for the year ended December 31, 2016. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead; for crude oil, the average NYMEX price was $42.75 per barrel, adjusted to $37.35 per barrel at the wellhead.

In 2015, we recorded a non-cash ceiling test impairment of oil and gas assets totaling approximately $250 million for the year ended December 31, 2015. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead; for crude oil, the average NYMEX price was $50.28 per barrel, adjusted to $44.72 per barrel at the wellhead.

During the second quarter of 2016, certain non-core assets were identified that were not suitable for inclusion in a possible Cost of Service Gas Program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the ceiling test impairments noted above.

Equity investments in unconsolidated subsidiaries

BHEP owned a 25% interest in a pipeline and gathering system, accounted for under the equity method of accounting. During the second quarter of 2015, due to sustained low commodity prices, recurring operating losses and future expectations we reviewed this investment interest for impairment utilizing the other-than-temporary impairment model under ASC 820, Fair Value Measurements. We valued the investment applying a market method approach utilizing assumptions consistent with similar known and measurable transactions. The carrying amount of this equity method investment exceeded the fair value, and we concluded the decline was considered to be other than temporary. As a result, we recorded a pre-tax impairment loss in 2015 of $4.4 million, the difference between the carrying amount and the fair value of the investment. In December of 2015, we sold our 25% interest in this pipeline and gathering system.

(22) OIL AND GAS RESERVES (Unaudited)

On November 1, 2017, we initiated the process of divesting all Oil and Gas segment assets in order to fully exit the oil and gas business. On November 1, 2017, we stopped the use of the full-cost method of accounting for our oil and gas business. The assets and liabilities have been classified as held for sale and the results of operations are included in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. As a result, our oil and gas reserves are no longer considered significant. For more information, see Note 21.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

	2016	2015
Acquisition of properties:		
Proved	$—	$1,407
Unproved	910	669
Exploration costs	1,102	35,434
Development costs	4,657	128,998
Asset retirement obligations incurred	—	566
Total costs incurred	$6,669	$167,074

Reserves

The following table summarizes BHEP’s quantities of proved developed and undeveloped oil, natural gas and NGL reserves, estimated using SEC-defined product prices, as of December 31, 2016 and 2015 and a reconciliation of the changes between these dates. The summary information presented for our estimated proved developed and undeveloped crude oil, natural gas, and NGL reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by Cawley Gillespie & Associates (CG&A), an independent consulting and engineering firm located in Fort Worth, Texas. CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Evaluation Engineers (SPEE), and has over 30 years of practical experience in petroleum engineering and over 28 years of experience in the estimation and evaluation of reserves. Reserves were determined consistent with SEC requirements using a 12-month average product price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Reserves for crude oil, natural gas, and NGLs are reported separately and then combined for a total MMcfe (where oil and NGLs in Mbbl are converted to an MMcfe basis by multiplying Mbbl by six). Such reserve estimates were inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

Minor differences in amounts may result in the following tables relating to oil and gas reserves due to rounding.

	2016			2015		
	Oil	Gas	NGL	Oil	Gas	NGL
	(in Mbbls of oil and NGL, and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	3,450	73,412	1,752	4,276	65,440	1,720
Production [a]	(319)	(9,430)	(133)	(371)	(10,058)	(102)
Sales	(570)	(1,291)	(17)	(11)	(828)	—
Additions - extensions and discoveries	3	52	—	199	24,462	232
Revisions to previous estimates	(322)	(8,173)	110	(643)	(5,604)	(98)
Balance at end of year	2,242	54,570	1,712	3,450	73,412	1,752
Proved developed reserves at end of year included above	2,242	54,570	1,712	3,436	73,390	1,752
Proved undeveloped reserves at the end of year included in above	—	—	—	14	22	—
NYMEX prices	$42.75	$2.48	$— [b]	$50.28	$2.59	$— [b]
Well-head reserve prices[c]	$37.35	$2.25	$11.92	$44.72	$1.27	$18.96

(a) Production for reserve calculations did not include volumes for natural gas liquids (NGLs) for historical periods.

(b) A specific NYMEX price for NGL was not available. Market prices for NGL are broken down by various liquid components, including ethane, propane, isobutane, normal butane, and natural gasoline. Each of these components is traded as an index. Ethane was not being recovered at any of the facilities that process our natural gas production.

(c) For reserves purposes, costs to gather gas previously netted from the gas price were reclassified into operating expenses in 2016, with approximate rates of $1.54/Mcf for Piceance, $0.92/Mcf for San Juan and $0.53/Mcf for all others. The sales price for natural gas was adjusted for transportation costs and other related deductions when applicable.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31 (in thousands):

	2016	2015
Unproved oil and gas properties	$18,547	$47,254
Proved oil and gas properties	1,043,558	1,008,466
Gross capitalized costs	1,062,105	1,055,720
Accumulated depreciation, depletion and amortization and valuation allowances	(1,000,091)	(888,775)
Net capitalized costs	$62,014	$166,945

Results of Operations

For more on oil and gas producing activities included in discontinued operations, see Note 21. Following is a summary of results of operations for producing activities for the years ended December 31 (in thousands):

	2016	2015
Revenue	$34,058	$43,283
Production costs	17,231	19,762
Depreciation, depletion and amortization	12,574	28,062
Impairment of long-lived assets	106,957	249,608
Total costs	136,762	297,432
Results of operations from producing activities before tax	(102,704)	(254,149)
Income tax benefit (expense)	37,916	93,743
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$(64,788)	$(160,406)

Unproved Properties

Unproved properties not subject to amortization at December 31, 2016 and 2015 consisted mainly of exploration costs on various existing work-in-progress projects as well as leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $0.9 million and $1.0 million of interest during 2016 and 2015, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool.
The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2016 and notes the year in which the associated costs were incurred (in thousands):

	2016	2015	Prior	Total
Leasehold acquisition cost	$963	$—	$ —	$963
Exploration cost	532	441	—	973
Capitalized interest	50	23	—	73
Total	$1,545	$464	$ —	$2,009

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure of discounted future net cash flows and changes relating to proved oil and gas reserves for the years ended December 31 (in thousands):

	2016	2015
Future cash inflows	$246,221	$295,173
Future production costs	(166,248)	(146,552)
Future development costs, including plugging and abandonment	(18,333)	(24,833)
Future net cash flows	61,640	123,788
10% annual discount for estimated timing of cash flows	(26,574)	(44,760)
Standardized measure of discounted future net cash flows	$35,066	$79,028

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31 (in thousands):

	2016	2015
Standardized measure - beginning of year	$79,028	$183,022
Sales and transfers of oil and gas produced, net of production costs	(4,314)	(29,948)
Net changes in prices and production costs	(32,698)	(127,199)
Extensions, discoveries and improved recovery, less related costs	—	15,718
Changes in future development costs	1,825	(7,387)
Development costs incurred during the period	—	27,211
Revisions of previous quantity estimates	(7,477)	(6,941)
Accretion of discount	7,903	18,870
Net change in income taxes	—	5,682
Sales of reserves	(9,201)	—
Standardized measure - end of year	$35,066	$79,028

Changes in the standardized measure from “revisions of previous quantity estimates” were driven by reserve revisions, modifications of production profiles and timing of future development. For all years presented, we had minimal net reserve revisions to prior estimates due to performance. Production forecast modifications were generally made at the well level each year through the reserve review process. These production profile modifications were based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments were reviewed each year and were often modified in response to current market conditions for items such as permitting and service availability.

(23) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2017 and 2016.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2017				
Revenue	$547,528	$341,829	$335,611	$455,298
Operating income (loss)	$150,186	$69,796	$79,559	$117,195
Income (loss) from continuing operations	$81,715	$25,927	$32,898	$67,835
Income (loss) from discontinued operations	$(1,569)	$(616)	$(1,300)	$(13,614)
Net income attributable to noncontrolling interest	$(3,623)	$(3,116)	$(3,935)	$(3,568)
Net income (loss) available for common stock	$76,523	$22,195	$27,663	$50,653
Amounts attributable to common shareholders:				
Net income (loss) from continuing operations	$78,092	$22,811	$28,963	$64,267
Net income (loss) from discontinued operations	$(1,569)	$(616)	$(1,300)	$(13,614)
Net income (loss) available for common stock	$76,523	$22,195	$27,663	$50,653
Income (loss) per share for continuing operations - Basic	$1.47	$0.43	$0.54	$1.21
Income (loss) per share for discontinued operations - Basic	$(0.03)	$(0.01)	$(0.02)	$(0.26)
Earnings (loss) per share - Basic	$1.44	$0.42	$0.52	$0.95
Income (loss) per share for continuing operations - Diluted	$1.42	$0.41	$0.52	$1.17
Income (loss) per share for discontinued operations - Diluted	$(0.03)	$(0.01)	$(0.02)	$(0.25)
Earnings (loss) per share - Diluted	1.39	0.40	0.50	0.92
Dividends paid per share	$0.445	$0.445	$0.445	$0.475
Common stock prices - High	$67.02	$72.02	$71.01	$69.79
Common stock prices - Low	$60.02	$65.37	$67.08	$57.01

Income from continuing operations for each quarter of 2017 included external incremental acquisition and transaction costs. We incurred after-tax external incremental acquisition and transaction expenses of $0.9 million during the first quarter, $0.3 million during the second quarter, $0.2 million during the third quarter and $1.3 million during the fourth quarter.

Included within the Income (loss) from continuing operations in the fourth quarter of 2017 is a net tax benefit of $7.6 million from the impact of the TCJA, as well as a tax benefit of $4.1 million from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

Included within the Loss from discontinued operations in the fourth quarter of 2017 is an after-tax non-cash impairment of oil and gas properties of $13.0 million.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2016				
Revenue	$441,584	$317,795	$324,147	$455,390
Operating income (loss)	$91,281	$63,725	$70,844	$110,330
Income (loss) from continuing operations	$45,320	$21,128	$24,964	$55,381
Income (loss) from discontinued operations	$(5,270)	$(17,845)	$(7,080)	$(33,967)
Net income attributable to noncontrolling interest	$(48)	$(2,614)	$(3,753)	$(3,246)
Net income (loss) available for common stock	$40,002	$669	$14,131	$18,168
Amounts attributable to common shareholders:				
Net income (loss) from continuing operations	45,272	18,514	21,211	52,135
Net income (loss) from discontinued operations	(5,270)	(17,845)	(7,080)	(33,967)
Net income (loss) available for common stock	40,002	669	14,131	18,168
Income (loss) per share for continuing operations - Basic	$0.88	$0.36	$0.41	$0.98
Income (loss) per share for discontinued operations - Basic	(0.10)	(0.35)	(0.14)	(0.64)
Earnings (loss) per share - Basic	$0.78	$0.01	$0.27	$0.34
Income (loss) per share for continuing operations - Diluted	$0.87	$0.35	$0.39	$0.96
Income (loss) per share for discontinued operations - Diluted	(0.10)	(0.34)	(0.13)	(0.63)
Earnings (loss) per share - Diluted	$0.77	$0.01	$0.26	$0.33
Dividends paid per share	$0.420	$0.420	$0.420	$0.420
Common stock prices - High	$61.13	$63.53	$64.58	$62.83
Common stock prices - Low	$44.65	$56.16	$56.86	$54.76

Income from continuing operations for each quarter of 2016 included external incremental acquisition and transaction costs. We incurred after-tax external incremental acquisition and transaction expenses of $15 million during the first quarter, $4.1 million during the second quarter, $4.1 million during the third quarter and $5.5 million during the fourth quarter.

Included with loss from discontinued operations in each quarter of 2016 are non-cash impairments of oil and gas properties. We recorded after-tax impairments of oil and gas properties of $8.8 million during the first quarter, $16 million during the second quarter, $7.9 million during the third quarter and $34 million during the fourth quarter.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2017. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2017, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 88 of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 55, has been Chairman and Chief Executive Officer since January 2016 and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President — Fuel Resources from 1997 to 2003. Mr. Emery has 28 years of experience with the Company.

Scott A. Buchholz, age 56, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 37 years of experience with the Company, including 28 years with Aquila.

Linden R. Evans, age 55, has been President and Chief Operating Officer of the Company since January 2016 and President and Chief Operating Officer — Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and served as our Associate Counsel from 2001 to 2003. Mr. Evans has 16 years of experience with the Company.

Brian G. Iverson, age 55, has been Senior Vice President, General Counsel and Chief Compliance Officer since April 2016. He served as Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to April 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 14 years of experience with the Company.

Richard W. Kinzley, age 52, has been Senior Vice President and Chief Financial Officer since January 2015. He served as Vice President - Corporate Controller from 2013 to 2014, Vice President - Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 18 years of experience with the Company.

Jennifer C. Landis, age 43, has been Senior Vice President - Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from 2013 to April 2016, and Director of Organization Development from 2008 to 2013. Ms. Landis has 16 years of experience with the Company.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2017 with respect to our equity compensation plans. These plans include the 2005 Omnibus Incentive Plan and 2015 Omnibus Incentive Plan.
Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	240,190 (1)	$ 44.83 (1)	979,464 (2)
Equity compensation plans not approved by security holders	—	$ —	—
Total	240,190	$ 44.83	979,464

(1) Includes 143,441 full value awards outstanding as of December 31, 2017, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares, STIP or common stock units. In addition, 267,284 shares of unvested restricted stock were outstanding as of December 31, 2017, which are not included in the above table because they have already been issued.

(2) Shares available for issuance are from the 2015 Omnibus Incentive Plan. The 2015 Omnibus Incentive Plan permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2018 Annual Meeting to Shareholders, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2017, 2016 and 2015

3. Exhibits

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

SCHEDULE II
BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

Description	Balance at Beginning of Year	Adjustments (a)	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
	(in thousands)					
Allowance for doubtful accounts:						
2017	$2,392	$ —	$ 4,926	$ 8,262	$ (12,499)	$ 3,081
2016	$1,741	$ 2,158	$ 2,704	$ 4,915	$ (9,126)	$ 2,392
2015	$1,516	$ —	$ 3,860	$ 4,132	$ (7,767)	$ 1,741

(a) Represents allowance balances added with the SourceGas acquisition.

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3. Exhibits

Exhibit Number	Description
2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).
2.2*	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015).
2.3*	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
3.2*	Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016). Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo

	Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 23, 2015).

4.5*	Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on November 23, 2015).
4.6*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008). First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).
10.4*†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).
10.5*†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008). Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.6*†	Black Hills Corporation 2015 Omnibus Incentive Plan (filed as Appendix B to the Registrant's Proxy Statement filed March 19, 2015).
10.7*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013). Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015).
10.8*†	Form of Restricted Stock Award for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.9 to the Registrant's Form 10-K for 2013). Form of Restricted Stock Award Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015).
10.9*†	Form of Restricted Stock Unit Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2013). Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015).
10.10*†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2015 (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2014). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016). Form of Performance Share Award Agreement effective for

awards granted on or after January 1, 2017.

10.11* Form of Short-term Incentive effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).

10.12* Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).

10.13* Change in Control Agreement dated November 15, 2016 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 16, 2016).

10.14*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on November 16, 2016).
10.15*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008). First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010). Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012). Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2014). Fourth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2016).
10.16†	Fifth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2018.
10.17*†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.18*	Equity Distribution Sales Agreement dated March 18, 2016 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on March 18, 2016).
10.19*	Equity Distribution Sales Agreement dated August 4, 2017 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on August 4, 2017).
10.20*	Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014).
10.21*	Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014).
10.22*	Third Amended and Restated Term Loan Credit Agreement, dated August 9, 2016 (relating to $340 million SourceGas Acquisition Credit Agreement - $0 balance at 12/31/2016) among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and J.P. Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on August 10, 2016).
10.23*	Second Amended and Restated Credit Agreement, dated August 9, 2016 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on August 10, 2016). Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of December 7, 2016 (filed as Exhibit 10.22 to the Registrant's Form 10-K for 2016).
10.24*	Credit Agreement dated August 9, 2016 (relating to $500 million, three-year term loan - $300 million balance at 12/31/2017), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks,

and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on August 10, 2016). Amendment No. 1 to Credit Agreement dated as of December 7, 2016 (filed as Exhibit 10.25 to the Registrant's Form 10-K for 2016).

10.25*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10 K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10 K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10 K for 1989).

10.26*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant’s Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data
101	Financial Statements in XBRL Format

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

BLACK HILLS CORPORATION

By: /S/ DAVID R. EMERY
David R. Emery, Chairman
and Chief Executive Officer

Dated: February 23, 2018

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.

/S/ DAVID R. EMERY David R. Emery, Chairman and Chief Executive Officer	Director and Principal Executive Officer	February 23, 2018
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 23, 2018
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 23, 2018
/S/ LINDA K. MASSMAN Linda K. Massman	Director	February 23, 2018
/S/ STEVEN R. MILLS Steven R. Mills	Director	February 23, 2018
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 23, 2018
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 23, 2018
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 23, 2018
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 23, 2018
/S/ JOHN B. VERING John B. Vering	Director	February 23, 2018
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 23, 2018

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