BLACK HILLS CORP /SD/
Form 10-Q
November 06, 2017

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2017

OR

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 IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701
Registrant's telephone number (605) 721-1700
Former name, former address, and former fiscal year if changed since last report
NONE

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 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 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

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

Class	Outstanding at October 31, 2017
Common stock, $1.00 par value	53,484,560 shares

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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:

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., a direct, wholly-owned subsidiary of Black Hills Gas Inc.
Stockton Storage	Arkansas Gas storage facility
ARMRP	At-Risk Meter Relocation Program
ASC	Accounting Standards Codification
ASU	Accounting Standards Update issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
Bbl	Barrel
BHC	Black Hills Corporation; the Company
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 South Dakota Electric	Includes Black Hills Power 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)

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
Btu	British thermal unit
CAPP	Customer Appliance Protection Plan

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 prices and a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties.
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
CIAC	Contribution In Aid of Construction
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 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.
Cost of Service Gas Program (COSG)	Proposed Cost of Service Gas Program designed to provide long-term natural gas price stability for the Company’s utility customers, along with a reasonable expectation of customer savings over the life of the program.
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CVA	Credit Valuation Adjustment
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
ECA	Energy Cost Adjustment - adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
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.
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
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.
GSRS	Gas System Reliability Surcharge
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.
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
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)
KCC	Kansas Corporation Commission
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MRP	Meter Relocation Program
MW	Megawatts
MWh	Megawatt-hours
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)
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOL	Net Operating Loss
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Peak View Wind Project	$109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm
PPA	Power 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 in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
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.
S&P	Standard and Poor's, a division of The McGraw-Hill Companies, Inc.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming and Montana
SSIR	System Safety and Integrity Rider
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.
VIE	Variable interest entity
Winter Storm Atlas	An October 2013 blizzard that impacted South Dakota Electric. It was the second most severe blizzard in Rapid City's history.

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, is 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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except per share amounts)			
Revenue	$342,138	$333,786	$1,244,119	$1,109,186
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	86,281	80,194	404,222	336,539
Operations and maintenance	114,648	115,103	354,152	334,706
Depreciation, depletion and amortization	49,434	48,925	146,744	140,637
Taxes - property, production and severance	13,092	12,114	40,804	36,991
Impairment of long-lived assets	—	12,293	—	52,286
Other operating expenses	164	6,748	3,301	40,730
Total operating expenses	263,619	275,377	949,223	941,889
Operating income	78,519	58,409	294,896	167,297
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(35,305)	(37,306)	(105,499)	(103,989)
Allowance for funds used during construction - borrowed	753	860	2,061	2,115
Capitalized interest	149	282	448	785
Interest income	402	912	700	2,513
Allowance for funds used during construction - equity	696	1,211	1,982	2,900
Other income (expense), net	189	160	29	801
Total other income (expense), net	(33,116)	(33,881)	(100,279)	(94,875)
Income before income taxes	45,403	24,528	194,617	72,422
Income tax benefit (expense)	(13,805)	(6,644)	(57,562)	(11,205)
Net income	31,598	17,884	137,055	61,217
Net income attributable to noncontrolling interest	(3,935)	(3,753)	(10,674)	(6,415)
Net income available for common stock	$27,663	$14,131	$126,381	$54,802
Earnings per share of common stock:				
Earnings per share, Basic	$0.52	$0.27	$2.38	$1.06
Earnings per share, Diluted	$0.50	$0.26	$2.29	$1.04
Weighted average common shares outstanding:				
Basic	53,243	52,184	53,208	51,583
Diluted	55,432	53,733	55,254	52,893
Dividends declared per share of common stock	$0.445	$0.420	$1.335	$1.260

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Net income	$31,598	$17,884	$137,055	$61,217
Other comprehensive income (loss), net of tax:				
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $17 and $19 for the three months ended September 30, 2017 and 2016 and $52 and $57 for the nine months ended September 30, 2017 and 2016, respectively)	(32)	(36)	(94)	(108)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(145) and $(171) for the three months ended September 30, 2017 and 2016 and $(445) and $(517) for the nine months ended September 30, 2017 and 2016, respectively)	269	323	797	966
Derivative instruments designated as cash flow hedges:				
Net unrealized gains (losses) on interest rate swaps (net of tax of $0 and $163 for the three months ended September 30, 2017 and 2016 and $0 and $10,930 for the nine months ended September 30, 2017 and 2016, respectively)	—	(302)	—	(20,200)
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(249) and $(294) for the three months ended September 30, 2017 and 2016 and $(779) and $(886) for the nine months ended September 30, 2017 and 2016, respectively)	464	546	1,449	1,644
Net unrealized gains (losses) on commodity derivatives (net of tax of $94 and $(423) for the three months ended September 30, 2017 and 2016 and $(442) and $(324) for the nine months ended September 30, 2017 and 2016, respectively)	(160)	(249)	755	(417)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $95 and $860 for the three months ended September 30, 2017 and 2016 and $344 and $3,337 for the nine months ended September 30, 2017 and 2016, respectively)	(166)	(1,469)	(590)	(5,781)
Other comprehensive income (loss), net of tax	375	(1,187)	2,317	(23,896)
Comprehensive income	31,973	16,697	139,372	37,321
Less: comprehensive income attributable to noncontrolling interest	(3,935)	(3,753)	(10,674)	(6,415)
Comprehensive income available for common stock	$28,038	$12,944	$128,698	$30,906

See Note 13 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of September 30, 2017	December 31, 2016	September 30, 2016
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$13,510	$13,580	$31,814
Restricted cash and equivalents	2,683	2,274	2,140
Accounts receivable, net	153,832	263,289	154,617
Materials, supplies and fuel	126,520	107,210	113,475
Derivative assets, current	657	4,138	4,382
Regulatory assets, current	61,023	49,260	50,561
Other current assets	26,793	27,063	30,032
Total current assets	385,018	466,814	387,021
Investments	12,947	12,561	12,416
Property, plant and equipment	6,615,098	6,412,223	6,306,119
Less: accumulated depreciation and depletion	(2,020,331)	(1,943,234)	(1,841,116)
Total property, plant and equipment, net	4,594,767	4,468,989	4,465,003
Other assets:			
Goodwill	1,299,454	1,299,454	1,300,379
Intangible assets, net	7,765	8,392	8,944
Regulatory assets, non-current	239,571	246,882	234,240
Derivative assets, non-current	—	222	183
Other assets, non-current	11,655	12,130	12,800
Total other assets, non-current	1,558,445	1,567,080	1,556,546
TOTAL ASSETS	$6,551,177	$6,515,444	$6,420,986

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)
(unaudited)

	As of		
	September 30, 2017	December 31, 2016	September 30, 2016
	(in thousands, except share amounts)		
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$95,595	$153,477	$110,630
Accrued liabilities	213,571	244,034	228,522
Derivative liabilities, current	1,562	2,459	1,941
Accrued income taxes, net	5,587	12,552	10,909
Regulatory liabilities, current	7,042	13,067	16,925
Notes payable	225,170	96,600	75,000
Current maturities of long-term debt	5,743	5,743	5,743
Total current liabilities	554,270	527,932	449,670
Long-term debt	3,109,864	3,211,189	3,211,768
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	605,744	535,606	533,865
Derivative liabilities, non-current	74	274	317
Regulatory liabilities, non-current	198,189	193,689	186,496
Benefit plan liabilities	149,803	173,682	171,633
Other deferred credits and other liabilities	137,251	138,643	141,007
Total deferred credits and other liabilities	1,091,061	1,041,894	1,033,318
Commitments and contingencies (See Notes 8, 10, 15, 16)			
Redeemable noncontrolling interest	—	4,295	4,206
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,524,529; 53,397,467; and 53,131,469 shares, respectively	53,525	53,397	53,131
Additional paid-in capital	1,147,922	1,138,982	1,123,527
Retained earnings	516,371	457,934	462,090
Treasury stock, at cost – 41,457; 15,258; and 22,368 shares, respectively	(2,448)	(791)	(1,155)
Accumulated other comprehensive income (loss)	(32,566)	(34,883)	(32,951)
Total stockholders' equity	1,682,804	1,614,639	1,604,642
Noncontrolling interest	113,178	115,495	117,382
Total equity	1,795,982	1,730,134	1,722,024
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$6,551,177	$6,515,444	$6,420,986

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Nine Months Ended September 30,	
	2017	2016
Operating activities:	(in thousands)	
Net income	$137,055	$54,802
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	146,744	140,637
Deferred financing cost amortization	6,212	4,002
Impairment of long-lived assets	—	52,286
Derivative fair value adjustments	1,931	(7,308)
Stock compensation	7,594	9,124
Deferred income taxes	64,672	38,578
Employee benefit plans	8,470	11,830
Other adjustments, net	(5,550)	(2,076)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(19,560)	(5,166)
Accounts receivable, unbilled revenues and other operating assets	107,026	78,869
Accounts payable and other operating liabilities	(101,471)	(117,631)
Regulatory assets - current	1,287	8,453
Regulatory liabilities - current	(4,328)	(8,181)
Contributions to defined benefit pension plans	(27,700)	(14,200)
Interest rate swap settlement	—	(28,820)
Other operating activities, net	(2,952)	(5,998)
Net cash provided by (used in) operating activities	319,430	209,201
Investing activities:		
Property, plant and equipment additions	(256,138)	(334,098)
Acquisition, net of long term debt assumed	—	(1,124,238)
Other investing activities	(250)	(860)
Net cash provided by (used in) investing activities	(256,388)	(1,459,196)
Financing activities:		
Dividends paid on common stock	(71,334)	(65,247)
Common stock issued	3,562	107,690
Sale of noncontrolling interest	—	216,370
Net (payments) borrowings of short-term debt	128,570	(1,800)
Long-term debt - issuances	—	1,767,608
Long-term debt - repayments	(104,307)	(1,162,872)
Distributions to noncontrolling interest	(12,884)	(4,516)
Other financing activities	(6,719)	(16,285)
Net cash provided by (used in) financing activities	(63,112)	840,948
Net change in cash and cash equivalents	(70)	(409,047)
Cash and cash equivalents, beginning of period	13,580	440,861
Cash and cash equivalents, end of period	$13,510	$31,814

See Note 14 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2016 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company," "us," "we," or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2016 Annual Report on Form 10-K filed with the SEC.

Segment Reporting

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Mining and Oil and Gas. 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.

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. We have initiated the process of divesting all Oil and Gas segment assets in order to fully exit the oil and gas business. We anticipate selling or otherwise disposing of all remaining oil and gas properties and assets by year-end 2018 and have retained advisors to accelerate the marketing and sales process. The Company's Condensed Consolidated Financial Statements and accompanying Notes as of and for the three and nine months ended September 30, 2017 include the Oil and Gas segment's assets and liabilities, results of operations and cash flows within continuing operations, as we did not meet the criteria for classifying assets as held for sale and presenting the segment's activities as discontinued operations during the quarter. See Note 20.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Condensed Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2017, December 31, 2016, and September 30, 2016 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2017 and September 30, 2016, and our financial condition as of September 30, 2017, December 31, 2016, and September 30, 2016, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. September 30, 2017 reflects a full nine months of activity from the SourceGas Acquisition on February 12, 2016, as compared to the nine months ended September 30, 2016 which reflects a partial period of approximately 7.5 months. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Revisions

Certain revisions have been made to prior years' financial information to conform to the current year presentation. The Company revised its presentation of cash as of December 31, 2016. The Company has banking arrangements at certain financial institutions whereby if required, payments of one account are cleared with cash from other accounts at the same financial institution; therefore, book overdrafts are presented on a combined basis by bank as cash and cash equivalents. Prior year amounts were corrected to conform with the current year presentation, which decreased cash and cash equivalents and accounts payable by $31 million as of September 30, 2016, and decreased net cash flows provided by operations by $15 million for the nine months ended September 30, 2016. We assessed the materiality of these changes, taking into account quantitative and qualitative factors, and determined them to be immaterial to the Condensed Consolidated Balance Sheet as of September

30, 2016 and to the Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2016. There is no impact to the Condensed Consolidated Statements of Income or the Condensed Consolidated Statements of Comprehensive Income for any period reported.

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 with early adoption on January 1, 2017 permitted. Entities will 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 currently expect to implement the standard on a modified retrospective basis effective January 1, 2018. We have substantially completed our assessment of all sources of revenue and are currently determining the impact that adoption of the new standard will have on our financial position, results of operations and cash flows. A majority of our revenues are from regulated tariff offerings that provide natural gas or electricity with a defined contractual term. For such arrangements, we expect that revenue from contracts with the customer will be equivalent to the electricity or gas delivered during that period. Therefore, we do not expect to have a significant shift in the timing or pattern of revenue recognition for regulated tariff based sales. We also continue to monitor outstanding industry implementation issues and assess the impacts to our current accounting policies and/or patterns of revenue recognition.

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 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 continue to assess the impact of this new standard on our financial statements and disclosures, and we monitor regulated utility industry implementation discussions and guidance. For our rate-regulated entities, we currently expect to capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities. 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. We will implement this standard effective January 1, 2018.

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 will use the retrospective transition method to implement this standard effective January 1, 2018. 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 all leases with a term greater than 12 months, 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. 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.

We currently expect to adopt this standard on January 1, 2019. 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, and other industry-related areas. We have begun the process of identifying and categorizing our lease contracts and evaluating our current business processes.

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.

Recently Adopted Accounting Standards

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 to retained earnings as of the date of adoption of $3.2 million in the Condensed Consolidated Balance Sheets, 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

2016 Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas (now referred to as Black Hills Gas Holdings). We acquired SourceGas for $1.1 billion of cash plus the assumption of $760 million of long-term debt. We finalized our purchase price allocation at December 31, 2016. See Note 2 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K for more details.

Pro Forma Results

The following unaudited pro forma financial information reflects the consolidated results of operations as if the SourceGas Acquisition had taken place on January 1, 2015. The unaudited pro forma financial information is presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or our future consolidated results.

The pro forma financial information does not reflect any potential cost savings from operating efficiencies resulting from the acquisition and does not include certain acquisition-related costs that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the three and nine months ended September 30, 2016 exclude approximately $3.8 million and $23 million, respectively, of after-tax transaction costs, including professional fees, employee related expenses and other miscellaneous costs.

	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2016
	(in thousands, except per share amounts)	
Revenue	$333,786	$1,188,148
Net income available for common stock	$17,376	$89,973
Earnings per share, Basic	$0.33	$1.74
Earnings per share, Diluted	$0.32	$1.70

Redemption of 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. The terms of the agreement provided us a call option to purchase the remaining interest beginning 366 days after the initial close of the SourceGas Transaction. In March 2017, we exercised our call option and purchased the remaining 0.5% equity interest in SourceGas for $5.6 million.

(3) BUSINESS SEGMENT INFORMATION

Segment information and Corporate activities included in the accompanying Condensed Consolidated Statements of Income were as follows (in thousands):

Three Months Ended September 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$181,238	$ 2,333	$27,324
Gas	142,821	73	(4,329)
Power Generation (b)	1,810	21,117	6,155
Mining	9,742	7,751	3,477
Oil and Gas	6,527	—	(2,712)
Corporate activities (c)	—	—	(2,252)
Inter-company eliminations	—	(31,274)	—
Total	$342,138	$ —	$27,663

Three Months Ended September 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)

			Available for Common Stock
Segment:			
Electric·	$ 171,754	$ 2,747	$ 24,181
Gas	141,445	—	(2,939)
Power Generation (b)	1,906	21,431	5,642
Mining	9,042	7,778	3,307
Oil and Gas (e)	9,639	—	(8,828)
Corporate activities (c)	—	—	(7,232)
Inter-company eliminations	—	(31,956)	—
Total	$ 333,786	$ —	$ 14,131

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Nine Months Ended September 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$518,925	$ 9,123	$68,386
Gas [(a)]	674,161	90	41,409
Power Generation [(b)]	5,382	62,907	18,017
Mining	26,500	22,485	9,048
Oil and Gas	19,151	—	(7,609)
Corporate activities [(c)(d)]	—	—	(2,870)
Inter-company eliminations	—	(94,605)	—
Total	$1,244,119	$ —	$126,381

Nine Months Ended September 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$493,845	$ 9,413	$ 62,625
Gas [(a)]	563,879	—	29,975
Power Generation [(b)]	5,304	63,055	19,907
Mining	20,498	23,651	6,969
Oil and Gas [(e)]	25,660	—	(35,277)
Corporate activities [(c)(d)]	—	—	(29,397)
Inter-company eliminations	—	(96,119)	—
Total	$1,109,186	$ —	$ 54,802

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(a) Gas Utility revenue increased for the nine months ended September 30, 2017 compared to the same period in the prior year primarily due to the addition of the SourceGas utilities on February 12, 2016.

(b) Net income (loss) available for common stock for the three and nine months ended September 30, 2017 and September 30, 2016 was net of net income attributable to noncontrolling interests of $3.9 million and $11 million, and $3.8 million and $6.4 million, respectively.

(c) Net income (loss) available for common stock for the three and nine months ended September 30, 2017 and September 30, 2016 included incremental, non-recurring acquisition costs, net of tax of $0.2 million and $1.5 million, and $4.0 million and $24 million respectively. The nine months ended September 30, 2017 and the three and nine months ended September 30, 2016 included $0.4 million, $1.7 million and $7.4 million, respectively, of after-tax internal labor costs attributable to the acquisition.

(d) Net income (loss) available for common stock for the nine months ended September 30, 2017 included a $1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years. Net income (loss) available for common stock for the nine months ended September 30, 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. See Note 18.

(e) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 included non-cash after-tax impairments of oil and gas properties of $7.9 million and $33 million, respectively. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Segment information and Corporate balances included in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

Total Assets (net of inter-company eliminations) as of:	September 30, 2017	December 31, 2016	September 30, 2016
Segment:			
Electric [(a)]	$2,911,919	$2,859,559	$2,814,408
Gas	3,288,104	3,307,967	3,170,571
Power Generation [(a)]	64,357	73,445	77,570
Mining	66,700	67,347	66,804
Oil and Gas [(b)]	105,963	96,435	158,981
Corporate activities	114,134	110,691	132,652
Total assets	$6,551,177	$6,515,444	$6,420,986

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(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) As a result of continued low commodity prices and our decision to divest non-core oil and gas assets, we recorded non-cash impairments of $107 million for the year ended December 31, 2016 and $52 million for the nine months ended September 30, 2016. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(4) ACCOUNTS RECEIVABLE

Following is a summary of Accounts receivable, net included in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

September 30, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 42,716	$29,762	$ (494)	$ 71,984
Gas Utilities	49,842	24,516	(1,190)	73,168
Power Generation	1,010	—	—	1,010
Mining	3,534	—	—	3,534
Oil and Gas	3,590	—	(83)	3,507
Corporate	629	—	—	629
Total	$ 101,321	$54,278	$ (1,767)	$ 153,832

December 31, 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
Oil and Gas	3,991	—	(13)	3,978

Corporate	2,228	—	—	2,228
Total	$ 140,889	$ 124,792	$ (2,392)	$ 263,289

September 30, 2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 44,747	$ 30,970	$ (580)	$ 75,137
Gas Utilities	48,057	23,582	(1,923)	69,716
Power Generation	1,165	—	—	1,165
Mining	3,612	—	—	3,612
Oil and Gas	3,341	—	(13)	3,328
Corporate	1,659	—	—	1,659
Total	$ 102,581	$ 54,552	$ (2,516)	$ 154,617

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	September 30, 2017	December 31, 2016	September 30, 2016
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$ 20,559	$ 17,491	$ 16,525
Deferred gas cost adjustments [(a) (d)]	1	12,833	15,329	12,172
Gas price derivatives [(a)]	3	11,297	8,843	14,405
Deferred taxes on AFUDC [(b)]	45	15,645	15,227	14,093
Employee benefit plans [(c)]	12	105,671	108,556	107,578
Environmental [(a)]	subject to approval	1,051	1,108	1,126
Asset retirement obligations [(a)]	44	514	505	507
Loss on reacquired debt [(a)]	30	21,067	22,266	18,077
Renewable energy standard adjustment [(b)]	5	1,956	1,605	1,694
Deferred taxes on flow through accounting [(c)]	35	41,900	37,498	33,136
Decommissioning costs [(e)]	6	13,989	16,859	17,271
Gas supply contract termination	5	21,402	26,666	28,164
Other regulatory assets [(a) (e)]	30	32,710	24,189	20,053
		$ 300,594	$ 296,142	$ 284,801
Regulatory liabilities				
Deferred energy and gas costs [(a) (d)]	1	$ 3,780	$ 10,368	$ 15,033
Employee benefit plan costs and related deferred taxes [(c)]	12	66,620	68,654	65,575
Cost of removal [(a)]	44	125,360	118,410	114,616
Revenue subject to refund	1	1,386	2,485	1,892
Other regulatory liabilities [(c)]	25	8,085	6,839	6,305
		$ 205,231	$ 206,756	$ 203,421

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(a) We are allowed 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) Our deferred energy, fuel cost and gas cost adjustments represent the cost of electricity and gas delivered to our electric and gas utility customers that is either higher or lower than current rates and will be recovered or refunded in future rates. 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.

(e) In accordance with a settlement agreement approved by the SDPUC on June 16, 2017, South Dakota Electric's decommissioning costs of approximately $11 million, vegetation management costs of approximately $14 million, and Winter Storm Atlas costs of approximately $2.0 million are being amortized over 6 years, effective July 1, 2017. Decommissioning costs and Winter Storm Atlas costs were previously amortized over a 10 year period ending September 30, 2024. The vegetation management costs were previously

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unamortized. The change in amortization periods for these costs will increase annual amortization expense by approximately $2.7 million.

(6) MATERIALS, SUPPLIES AND FUEL

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

	September 30, 2017	December 31, 2016	September 30, 2016
Materials and supplies	$ 73,938	$ 68,456	$ 67,257
Fuel - Electric Utilities	2,993	3,667	4,282
Natural gas in storage held for distribution	49,589	35,087	41,936
Total materials, supplies and fuel	$ 126,520	$ 107,210	$ 113,475

(7) EARNINGS PER SHARE

A reconciliation of share amounts used to compute Earnings (loss) per share in the accompanying Condensed Consolidated Statements of Income was as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income available for common stock	$27,663	$14,131	$126,381	$54,802
Weighted average shares - basic	53,243	52,184	53,208	51,583
Dilutive effect of:				
Equity Units [(a)]	2,015	1,414	1,872	1,191
Equity compensation	174	135	174	119
Weighted average shares - diluted	55,432	53,733	55,254	52,893

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(a) Calculated using the treasury stock method.

The following outstanding securities were excluded in the computation of diluted net income (loss) per share as their inclusion would have been anti-dilutive (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Equity compensation	—	2	—	4
Anti-dilutive shares	—	2	—	4

(8) NOTES PAYABLE AND LONG-TERM DEBT

We had the following notes payable outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	September 30, 2017		December 31, 2016		September 30, 2016	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$—	$25,391	$96,600	$36,000	$75,000	$30,500
CP Program	225,170	—	—	—	—	—
Total	$225,170	$25,391	$96,600	$36,000	$75,000	$30,500

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 extend the term through August 9, 2021 with two one-year extension options (subject to consent from 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, 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 September 30, 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 the nine months ended September 30, 2017 and our notes outstanding as of September 30, 2017 were $225 million. As of September 30, 2017, the weighted average interest rate on CP Program borrowings was 1.46%.

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 and 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:

	As of September 30, 2017	Covenant Requirement
Consolidated Indebtedness to Capitalization Ratio	61%	Less than 65%

As of September 30, 2017, we were in compliance with this covenant.

Long-Term Debt

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.

(9) EQUITY

A summary of the changes in equity is as follows:

Nine Months Ended September 30, 2017	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2016	$ 1,614,639	$ 115,495	$ 1,730,134
Net income (loss)	126,381	10,567	136,948
Other comprehensive income (loss)	2,317	—	2,317
Dividends on common stock	(71,334)	—	(71,334)
Share-based compensation	5,853	—	5,853
Issuance of common stock	—	—	—
Dividend reinvestment and stock purchase plan	2,300	—	2,300
Redeemable noncontrolling interest	(886)	—	(886)
Cumulative effect of ASU 2016-09 implementation	3,714	—	3,714
Other stock transactions	(180)	—	(180)
Distribution to noncontrolling interest	—	(12,884)	(12,884)
Balance at September 30, 2017	$ 1,682,804	$ 113,178	$ 1,795,982

Nine Months Ended September 30, 2016	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2015	$ 1,465,867	$ —	$ 1,465,867
Net income (loss)	54,802	6,402	61,204
Other comprehensive income (loss)	(23,896)	—	(23,896)
Dividends on common stock	(65,247)	—	(65,247)
Share-based compensation	3,822	—	3,822
Issuance of common stock	105,238	—	105,238
Dividend reinvestment and stock purchase plan	2,242	—	2,242
Other stock transactions	(24)	—	(24)
Sale of noncontrolling interest	61,838	115,496	177,334
Distribution to noncontrolling interest	—	(4,516)	(4,516)
Balance at September 30, 2016	$ 1,604,642	$ 117,382	$ 1,722,024

At-the-Market Equity Offering Program

On August 4, 2017, we renewed the ATM equity offering program initiated in March 2016 which reset the size of the ATM equity offering 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 during the nine months ended September 30, 2017 under the ATM equity offering program. During the three months ended September 30, 2016, we sold 819,442 shares of common stock for $49 million, net of $0.5 million in commissions, under the ATM equity offering program. During the nine months ended September 30, 2016, we sold and issued under the ATM equity offering program an aggregate of 1,750,091 shares of common stock, with settlement dates through September 30, 2016, for $106 million, net of $1.1 million in commissions.

Sale of Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns 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.

This partial sale was recorded as an equity transaction with no resulting gain or loss on the sale. Further, 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 the noncontrolling interest are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

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:

	September 30, 2017	December 31, 2016	September 30, 2016
	(in thousands)		
Assets			
Current assets	$14,732	$12,627	$14,191
Property, plant and equipment of variable interest entities, net	$211,380	$218,798	$220,818
Liabilities			
Current liabilities	$3,275	$4,342	$3,353

(10) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation 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 as discussed in our 2016 Annual Report on Form 10-K.

Market Risk

Market risk is the potential loss that might 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 natural long position in crude oil and natural gas reserves and production, our retail natural gas marketing activities, and our fuel procurement for certain of our gas-fired generation assets.

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 on 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 derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income are detailed below and in Note 11.

Oil and Gas

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on our futures and swaps. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue in the accompanying Condensed Consolidated Statements of Income.

The contract or notional amounts and terms of the crude oil futures and natural gas futures and swaps held at our Oil and Gas segment are composed of short positions. We had the following short positions as of:

	September 30, 2017			December 31, 2016			September 30, 2016		
	Crude Oil Futures	Crude Oil Options	Natural Gas Futures and Swaps	Crude Oil Futures	Crude Oil Options	Natural Gas Futures and Swaps	Crude Oil Futures	Crude Oil Options	Natural Gas Futures and Swaps
Notional [(a)]	54,000	9,000	540,000	108,000	36,000	2,700,000	159,000	36,000	1,625,000
Maximum terms in months [(b)]	15	3	3	24	12	12	27	15	15

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(a) Crude oil futures and call options in Bbls, natural gas in MMBtus.
(b) Term reflects the maximum forward period hedged.

Based on September 30, 2017 prices, a $0.1 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Concurrent with the divestiture of our Oil and Gas Business, our existing oil and gas derivative contracts are expected to be unwound within the next six months. Accordingly, we have de-designated our hedge positions in our Oil and Gas Business effective November 1, 2017. See Note 20.

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, and 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 Condensed 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 Condensed Consolidated Balance Sheets in accordance with state commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Condensed Consolidated Statements of Income.

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 October 2017 through December 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with 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 Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income. Effectiveness of our hedging position is evaluated at inception of the hedge, upon occurrence of a triggering event and as of the end of each quarter.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our Utilities are composed of both long and short positions. We were in a net long position as of:

	September 30, 2017		December 31, 2016		September 30, 2016	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	10,250,000	39	14,770,000	48	17,740,000	51
Natural gas options purchased, net	7,360,000	17	3,020,000	5	6,540,000	17
Natural gas basis swaps purchased	9,170,000	39	12,250,000	48	13,650,000	51
Natural gas over-the-counter swaps, net [(b)]	4,600,000	20	4,622,302	28	4,749,000	20
Natural gas physical contracts, net	21,071,714	38	21,504,378	10	15,666,202	13

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(a) Term reflects the maximum forward period hedged.
(b) 2,260,000 MMBtus were designated as cash flow hedges for the natural gas fixed for float swaps purchased.

Based on September 30, 2017 prices, a $0.3 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

In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to reduce the interest rate risk 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 on August 10, 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 a component of interest expense over the ten-year life of the $400 million unsecured senior note issued on August 19, 2016. Amortization of approximately $2.9 million, which includes the amortization of the $28 million loss currently deferred in AOCI will be recognized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. 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 Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	September 30, 2017 Designated Interest Rate Swaps	December 31, 2016 Designated Interest Rate Swap [(a)]	September 30, 2016 Designated Interest Rate Swaps [(a)]
Notional	$ —	$ 50,000	$ 75,000
Weighted average fixed interest rate	— %	4.94 %	4.97 %
Maximum terms in months	0	1	4
Derivative liabilities, current	$ —	$ 90	$ 654

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(a) The $25 million in swaps expired in October 2016 and 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.

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Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three and nine months ended September 30, 2017 and 2016 (in thousands). Note that this presentation does not reflect 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.

Three Months Ended September 30, 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	$ (713)	Interest expense	$ —
Commodity derivatives	Revenue	295	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(34)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (452)		$ —

Three Months Ended September 30, 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	$ (840)	Interest expense	$ —
Commodity derivatives	Revenue	2,201	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	128	Fuel, purchased power and cost of natural gas sold	—
Total		$ 1,489		$ —

Nine Months Ended September 30, 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	$ (2,228)	Interest expense	$ —
Commodity derivatives	Revenue	954	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(20)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (1,294)		$ —

Nine Months Ended September 30, 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	$ (2,530)	Interest expense	$ —
Commodity derivatives	Revenue	9,140	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(23)	Fuel, purchased power and cost of natural gas sold	—
Total		$ 6,587		$ —

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 three and nine months ended September 30, 2017 and 2016. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts, if any, are immediately recognized in the Consolidated Statements of Income as incurred.

	Three Months Ended September 30,	
	2017	2016
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate swaps	$—	$(787)
Forward commodity contracts	(254)	174
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	713	1,162
Forward commodity contracts	(261)	(2,329)
Total other comprehensive income (loss) from hedging	$198	$(1,780)

	Nine Months Ended September 30,	
	2017	2016
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate swaps	$—	$(31,452)
Forward commodity contracts	1,197	(92)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	2,228	2,852
Forward commodity contracts	(934)	4,459
Total other comprehensive income (loss) from hedging	$2,491	$(24,233)

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 for the three and nine months ended September 30, 2017 and 2016 (in thousands). Note that this presentation does not reflect 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.

		Three Months Ended September 30,	
		2017	2016
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
Commodity derivatives	Revenue	$(53)	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(322)	(342)
		$(375)	$ (342)

		Nine Months Ended September 30,	
		2017	2016
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
Commodity derivatives	Revenue	$90	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(1,822)	2,492
		$(1,732)	$ 2,492

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. The net unrealized losses included in our Regulatory assets related to the hedges in our Utilities were $11 million, $8.8 million and $14 million at September 30, 2017, December 31, 2016 and September 30, 2016, respectively.

(11) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. 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. For additional information, see Notes 1, 9, 10 and 11 to the Consolidated Financial Statements included in our 2016 Annual Report on Form 10-K filed with the SEC.

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 when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity contracts for our Oil and Gas segment are valued using the market approach and include exchange-traded futures, basis swaps and call options. Fair value was derived using exchange quoted settlement prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through third-party sources and therefore support Level 2 disclosure.

Utilities Segments:

- The commodity contracts for our Utilities Segments, are valued using the market approach and include exchange-traded futures, options, basis swaps and over-the-counter swaps and options (Level 2) for natural gas contracts. For exchange-traded futures, options and basis swap assets and liabilities, fair value was derived using broker quotes validated by the exchange settlement pricing for the applicable contract. For over-the-counter instruments, the fair value is obtained by utilizing a nationally recognized service that obtains observable inputs to compute the fair value, which we validate by comparing our valuation with the counterparty. The fair value of these swaps includes a CVA component based on the credit spreads of the counterparties when we are in an unrealized gain position or on our own credit spread when we are in an unrealized loss position.

Corporate Activities:

- As of September 30, 2017, we no longer have derivatives within our corporate activities as our interest rate swaps matured in January 2017. The interest rate swaps that were in place prior to January 2017 were valued using the market approach. We established fair value by obtaining price quotes directly from the counterparty which were based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty was 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 included a CVA component. The CVA considered 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 utilized observable inputs supporting a Level 2 disclosure by using the credit default spread of the obligor, if available, or a generic credit default spread curve that took into account our credit ratings, and the credit rating of our counterparty.

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. 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.

The following tables set forth by level within the fair value hierarchy are gross assets and gross liabilities and related offsetting cash collateral and counterparty netting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

	As of September 30, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 769	$ —	$ (544)	$ 225
Commodity derivatives — Utilities	—	2,880	—	(2,448)	432
Total	$ —	$ 3,649	$ —	$ (2,992)	$ 657
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 114	$ —	$ —	$ 114
Commodity derivatives — Utilities	—	12,647	—	(11,125)	1,522
Total	$ —	$ 12,761	$ —	$ (11,125)	$ 1,636

	As of December 31, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 2,886	$ —	$ (2,733)	$ 153
Commodity derivatives —Utilities	—	7,469	—	(3,262)	4,207
Total	$ —	$ 10,355	$ —	$ (5,995)	$ 4,360
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 1,586	$ —	$ —	$ 1,586
Commodity derivatives — Utilities	—	12,201	—	(11,144)	1,057
Interest rate swaps	—	90	—	—	90
Total	$ —	$ 13,877	$ —	$ (11,144)	$ 2,733

	As of September 30, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 2,882	$ —	$ —	$ 2,882
Commodity derivatives — Utilities	—	5,330	—	(3,647)	1,683
Total	$ —	$ 8,212	$ —	$ (3,647)	$ 4,565
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 705	$ —	$ —	$ 705
Commodity derivatives — Utilities	—	16,130	—	(15,231)	899
Interest rate swaps	—	654	—	—	654
Total	$ —	$ 17,489	$ —	$ (15,231)	$ 2,258

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 (in thousands):

As of September 30, 2017

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 227	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	511
Commodity derivatives	Derivative liabilities — non-current	—	59
Total derivatives designated as hedges		$ 227	$ 570
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 430	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	1,051
Commodity derivatives	Derivative liabilities — non-current	—	15
Total derivatives not designated as hedges		$ 430	$ 1,066

As of December 31, 2016

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,161	$ —
Commodity derivatives	Derivative assets — non-current	124	—
Commodity derivatives	Derivative liabilities — current	—	1,090
Commodity derivatives	Derivative liabilities — non-current	—	238
Interest rate swaps	Derivative liabilities — current	—	90
Total derivatives designated as hedges		$ 1,285	$ 1,418
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 2,977	$ —
Commodity derivatives	Derivative assets — non-current	98	—
Commodity derivatives	Derivative liabilities — current	—	1,279
Commodity derivatives	Derivative liabilities — non-current	—	36
Total derivatives not designated as hedges		$ 3,075	$ 1,315

As of September 30, 2016

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 2,919	$ —
Commodity derivatives	Derivative assets — non-current	66	—
Commodity derivatives	Derivative liabilities — current	—	479
Commodity derivatives	Derivative liabilities — non-current	—	256
Interest rate swaps	Derivative liabilities — current	—	654
Total derivatives designated as hedges		$ 2,985	$ 1,389
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,463	$ —
Commodity derivatives	Derivative assets — non-current	117	—
Commodity derivatives	Derivative liabilities — current	—	808
Commodity derivatives	Derivative liabilities — non-current	—	61
Total derivatives not designated as hedges		$ 1,580	$ 869

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about the fair value measurements of their assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 18 to the Consolidated Financial Statements included in our 2016 Annual Report on Form 10-K.

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 11, were as follows (in thousands) as of:

	September 30, 2017		December 31, 2016		September 30, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$13,510	$13,510	$13,580	$13,580	$31,814	$31,814
Restricted cash and equivalents [(a)]	$2,683	$2,683	$2,274	$2,274	$2,140	$2,140
Notes payable [(b)]	$225,170	$225,170	$96,600	$96,600	$75,000	$75,000
Long-term debt, including current maturities [(c) (d)]	$3,115,607	$3,362,971	$3,216,932	$3,351,305	$3,217,511	$3,525,362

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(a) Carrying value approximates fair value due to either the short-term length of maturity or variable interest rates that approximate prevailing market rates, and therefore is classified in Level 1 in the fair value hierarchy.

(b) Notes payable consist of commercial paper borrowings and borrowings on our Revolving Credit Facility. 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.

(13) OTHER COMPREHENSIVE INCOME (LOSS)

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 for the period, net of tax (in thousands):

	Location on the Condensed Consolidated Statements of Income	Amount Reclassified from AOCI			
		Three Months Ended		Nine Months Ended	
		September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$(713)	$ (840)	$(2,228)	$(2,530)
Commodity contracts	Revenue	295	2,201	954	9,140
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(34)	128	(20)	(23)
		(452)	1,489	(1,294)	6,587
Income tax	Income tax benefit (expense)	154	(566)	435	(2,450)
Total reclassification adjustments related to cash flow hedges, net of tax		$(298)	$ 923	$(859)	$ 4,137
Amortization of components of defined benefit plans:					
Prior service cost	Operations and maintenance	$49	$ 55	$146	$ 165
Actuarial gain (loss)	Operations and maintenance	(414)	(494)	(1,242)	(1,483)
		(365)	(439)	(1,096)	(1,318)
Income tax	Income tax benefit (expense)	128	152	393	460
Total reclassification adjustments related to defined benefit plans, net of tax		$(237)	$ (287)	$(703)	$ (858)
Total reclassifications		$(535)	$ 636	$(1,562)	$ 3,279

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Balances by classification included within AOCI, net of tax on the accompanying Condensed 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	—	755	—	755
Amounts reclassified from AOCI	1,449	(590)	703	1,562
Ending Balance September 30, 2017	$(16,660)	$ (68)	$(15,838)	$(32,566)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
Balance as of December 31, 2015	$(341)	$ 7,066	$(15,780)	$(9,055)
Other comprehensive income (loss) before reclassifications	(20,200)	(417)	—	(20,617)
Amounts reclassified from AOCI	1,644	(5,781)	858	(3,279)
Ending Balance September 30, 2016	$(18,897)	$ 868	$(14,922)	$(32,951)

(14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine Months Ended	September 30, 2017	September 30, 2016
	(in thousands)	
Non-cash investing and financing activities—		
Property, plant and equipment acquired with accrued liabilities	$35,065	$44,140
Increase (decrease) in capitalized assets associated with asset retirement obligations	$1,362	$(2,285)
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$(101,840)	$(82,639)
Income taxes, net	$1	$(1,168)

(15) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

The components of net periodic benefit cost for the Defined Benefit Pension Plans were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Service cost	$1,759	$2,078	$5,276	$6,234
Interest cost	3,880	3,936	11,640	11,808
Expected return on plan assets	(6,130)	(5,766)	(18,388)	(17,297)
Prior service cost	15	15	44	45
Net loss (gain)	1,002	1,793	3,005	5,379
Net periodic benefit cost	$526	$2,056	$1,577	$6,169

Defined Benefit Postretirement Healthcare Plans

The components of net periodic benefit cost for the Defined Benefit Postretirement Healthcare Plans were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Service cost	$575	$467	$1,725	$1,401
Interest cost	533	485	1,600	1,455
Expected return on plan assets	(79)	(70)	(237)	(210)
Prior service cost (benefit)	(109)	(107)	(327)	(321)
Net loss (gain)	125	84	375	252
Net periodic benefit cost	$1,045	$859	$3,136	$2,577

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

The components of net periodic benefit cost for the Supplemental Non-qualified Defined Benefit and Defined Contribution Plans were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Service cost	$612	$623	$2,048	$1,530
Interest cost	319	314	957	943
Prior service cost	—	1	1	2
Net loss (gain)	251	207	751	621
Net periodic benefit cost	$1,182	$1,145	$3,757	$3,096

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust account. On July 24, 2017, we made contributions to the Defined Benefit Pension Plan in the amount of approximately $13 million. On September 15, 2017, we made an additional contribution of $15 million to reduce our Pension Benefit Guaranty Corporation premiums and offset the forecasted increase in pension expense due to low bond yields which impact the pension discount rate. Contributions to the Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions made in 2017 and anticipated contributions for 2017 and 2018 are as follows (in thousands):

	Contributions Made	Contributions Made	Additional Contributions	Contributions
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Anticipated for 2017	Anticipated for 2018
Defined Benefit Pension Plan	$ 27,700	$ 27,700	$ —	$ 12,700
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,270	$ 3,810	$ 1,270	$ 5,115
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 395	$ 1,187	$ 396	$ 1,682

(16) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of September 30, 2017, we were in compliance with the debt 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 stockholders 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.

Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions and financing agreements. As of September 30, 2017, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(17) IMPAIRMENT OF ASSETS

Long-lived Assets

Our Oil and Gas segment accounts for oil and gas activities under the full cost method of accounting. Under the full cost method, all productive and non-productive costs related to acquisition, exploration, development, abandonment and reclamation activities are capitalized. These 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. Any costs in excess of the ceiling are written off as a non-cash charge.

There were no impairments for the nine months ended September 30, 2017. In determining the ceiling value of our assets under the full cost accounting rules of the SEC, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. At September 30, 2017, the average NYMEX natural gas price was $3.00 per Mcf, adjusted to $2.66 per Mcf at the wellhead; the average NYMEX crude oil price was $49.81 per barrel, adjusted to $45.58 per barrel at the wellhead. At September 30, 2016, the average NYMEX natural gas price was $2.28 per Mcf, adjusted to $1.03 per Mcf at the wellhead; the average NYMEX crude oil price was $41.68 per barrel, adjusted to $35.88 per barrel at the wellhead. During the three and nine months ended September 30, 2016, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $12 million and $38 million, respectively.

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 impairments noted above.

(18) INCOME TAXES

The effective tax rate differs from the federal statutory rate as follows:

	Three Months Ended September 30,	
Tax (benefit) expense	2017	2016
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [(a)]	(1.0)	(4.0)
Percentage depletion in excess of cost	(1.1)	(2.3)
Accounting for uncertain tax positions adjustment	(0.9)	(2.4)
Noncontrolling interest [(b)]	(3.0)	(3.7)
Tax credits [(c)]	(1.5)	—
Effective tax rate adjustment [(d)]	3.9	7.2
Flow-through adjustments	(1.7)	(2.2)
AFUDC equity	(0.4)	(0.6)
Other tax differences	1.1	0.1
	30.4 %	27.1 %

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(a) In the three months ending September 30, 2017 and 2016, the state income tax benefit is primarily attributable to favorable flow-through adjustments and a pretax net loss at state tax accruing companies. 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.

(b) The adjustment reflects the noncontrolling interest attributable to the sale of 49.9% of the membership interests of Colorado IPP in April 2016.

(c) The increase in tax credits is due to the production tax credits for the Peak View wind farm and marginal gas well tax credit for the oil and gas segment.

(d) Adjustment to reflect the projected annual effective tax rate, pursuant to ASC 740-270.

	Nine Months Ended September 30,	
Tax (benefit) expense	2017	2016
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [(a)]	0.5	1.7
Percentage depletion in excess of cost [(b)]	(0.7)	(9.7)
Accounting for uncertain tax positions adjustment [(c)]	(0.2)	(7.7)
Noncontrolling interest [(d)]	(1.9)	(2.5)
IRC 172(f) carryback claim [(e)]	(1.0)	—
Tax credits [(f)]	(1.7)	—
Effective tax rate adjustment [(g)]	0.3	0.1
Flow-through adjustments [(h)]	(1.2)	(1.9)
Transaction costs	—	1.4
Other tax differences	0.5	(0.9)
	29.6 %	15.5 %

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(a) The lower state income tax expense in 2017 is lower primarily attributable to favorable flow-through adjustments. 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.

(b) The tax benefit for the nine months ended September 30, 2016 relates to additional percentage depletion deductions that are being claimed with respect to the oil and gas properties involving prior tax years. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 barrels of oil equivalent as allowed under the Internal Revenue Code.

(c) The tax benefit for the nine months ended September 30, 2016 relates to the release of after-tax interest expense that was previously accrued with respect to the liability for uncertain tax positions involving the like-kind exchange transaction effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. In addition, the tax benefit includes the release of reserves involving research and development credits and deductions. Both adjustments are the result of a re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(d) Black Hills Colorado IPP went from a single member LLC, wholly-owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9% of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision is not recorded.

(e) In Q1 2017, the Company filed amended income tax returns for the years 2006 through 2008 to carryback specified liability losses in accordance with IRC172(f). As a result of filing the amended returns, the Company's accrued tax liability interest decreased, certain valuation allowances increased and the previously recorded domestic production activities deduction decreased.

(f) The tax credits for the nine months ended September 30, 2017 are the result of Colorado Electric placing the Peak View Wind Project into service in November 2016. The Peak View Wind Project began generating production tax credits during the fourth quarter of 2016.

(g) Adjustment to reflect our 2017 and 2016 annual projected effective tax rate, pursuant to ASC 740-270.

(h) The flow-through adjustments related primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. In addition, flow-through adjustments were recorded related to an accounting method change for tax purposes that allows us to take a current tax deduction for certain indirect costs that continue to be capitalized for book purposes. 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.

In the first quarter of 2016, we reached an agreement in principle with IRS Appeals in regards to the like-kind exchange transaction associated with the gain deferred from the tax treatment related to the 2008 IPP Transaction and the Aquila Transaction. An agreement in principle was also reached with respect to research and development credits and deductions. Both issues were the subject of an IRS Appeals process involving the 2007 to 2009 tax years. We reversed approximately $35 million of the liability for unrecognized tax benefits, including interest, during the first quarter of 2016. The vast majority of such reversal was to restore accumulated deferred income taxes. We reversed accrued after-tax interest expense and tax credits of approximately $5.1 million associated with these liabilities in the first quarter of 2016. The cash taxes due as a result of the agreement in principle with IRS Appeals is estimated to be $8.0 million excluding interest.

(19) ACCRUED LIABILITIES

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

	September 30, 2017	December 31, 2016	September 30, 2016
Accrued employee compensation, benefits and withholdings	$54,134	$56,926	$57,203
Accrued property taxes	39,564	40,004	37,156
Customer deposits and prepayments	45,711	51,628	51,137
Accrued interest and contract adjustment payments	30,977	45,503	42,612
CIAC current portion	1,575	—	5,465
Other (none of which is individually significant)	41,610	49,973	34,949
Total accrued liabilities	$213,571	$244,034	$228,522

(20) SUBSEQUENT EVENTS

Divestiture of Oil and Gas Business

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. We have initiated the process of divesting all Oil and Gas segment assets in order to fully exit the oil and gas business. We anticipate selling or otherwise disposing of all remaining oil and gas properties and assets by year-end 2018 and have retained advisors to accelerate the marketing and sales process. The Company's Condensed Consolidated Financial Statements and accompanying Notes as of and for the three and nine months ended September 30, 2017 include the Oil and Gas segment's assets and liabilities, results of operations and cash flows within continuing operations, as we did not meet the criteria for classifying assets as held for sale and presenting the segment's activities as discontinued operations. Effective in the fourth quarter of 2017, our Oil and Gas segment assets and liabilities will be classified as held for sale, and the Oil and Gas results of operations and cash flows will be presented as discontinued operations. When these assets are classified as held for sale, they will be reviewed for impairment which could result in further impairment charges in the future.

Revenue and net loss for our Oil and Gas segment for the three and nine months ended September 30, 2017 and 2016 were as follows:

	Three Months Ended		Nine Months Ended	
(in thousands)	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
Revenue	$6,527	$9,639	$19,151	$25,660
Net (loss) available for common stock	$(2,712)	$(8,828)	$(7,609)	$(35,277)

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

We are a customer-focused, growth-oriented 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 208,500 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, Nebraska and Wyoming subsidiaries. Our Gas Utilities distribute and transport natural gas through our pipeline network to approximately 1,030,800 natural gas customers. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

We also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 55,000 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, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP primarily provide appliance repair services to approximately 61,000 and 33,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services primarily 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.

Oil and Gas: Our Oil and Gas segment engages in the production of crude oil and natural gas, primarily in the Rocky Mountain region. In the fourth quarter of 2017, we initiated the process of divesting of all remaining Oil and Gas segment assets in order to fully exit the oil and gas business. We anticipate the divestiture process will be complete by year-end 2018. The Company's Condensed Consolidated Financial Statements and accompanying Notes as of and for the three and nine months ended September 30, 2017 include the Oil and Gas segment's assets and liabilities, results of operations and cash flows within continuing operations, as we did not meet the criteria for classifying assets as held for sale and presenting the segment's activities as discontinued operations during the quarter. See Note 20 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q for more information.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for our electric utilities is June through August while the normal peak usage season for our gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2017 and 2016, and our financial condition as of September 30, 2017, December 31, 2016 and September 30, 2016, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 73.

The segment information does not include inter-company eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016. Net income available for common stock for the three months ended September 30, 2017 was $28 million, or $0.50 per share, compared to Net income available for common stock of $14 million, or $0.26 per share, reported for the same period in 2016. The Net income available for common stock for the three months ended September 30, 2017 increased over the same period in the prior year primarily due to a decrease in after-tax impairment charges on our oil and gas properties, lower after-tax corporate expenses, and higher earnings at our Electric Utilities. These are partially offset by lower earnings at our Gas Utilities. The variance to the prior year included the following:

- A decrease in non-cash after-tax impairment charges of approximately $7.9 million on our oil and gas properties;
- Corporate expenses decreased primarily due to a reduction of $3.8 million of after-tax acquisition and transition costs;
- Electric Utilities' earnings increased $3.1 million driven primarily by returns on prior year generation investments; and
- Gas Utilities' earnings decreased $1.4 million primarily due to the impact of cooler summer temperatures and higher precipitation on summer irrigation load delivered to agricultural customers.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016. Net income available for common stock for the nine months ended September 30, 2017 was $126 million, or $2.29 per share, compared to Net income available for common stock of $55 million, or $1.04 per share, reported for the same period in 2016. The Net income available for common stock for the nine months ended September 30, 2017 increased over the same period in the prior year primarily due to higher earnings at our Gas Utilities, Electric Utilities and Mining segments, lower corporate expenses, and a decrease in impairment charges on our oil and gas properties, partially offset by lower earnings at our Power Generation segment and by tax benefits realized during the same period in the prior year. The variance to the prior year included the following:

- Earnings at our Oil and Gas segment increased $28 million primarily due to prior year non-cash after-tax impairments on our oil and gas properties of approximately $33 million, partially offset by a prior year $5.8 million tax benefit recognized from additional percentage depletion deductions claimed with respect to our oil and gas properties;
- Corporate expenses decreased $27 million compared to the same period in the prior year driven primarily by a $23 million reduction of after-tax acquisition and transition costs;
- Gas Utilities' earnings increased $11 million with a full nine months of earnings from our acquired SourceGas utilities compared to approximately 7.5 months in the same period of the prior year;
- Electric Utilities' earnings increased $5.8 million driven primarily by returns on prior year generation investments;
- Earnings at our Mining segment increased $2.1 million due to an increase in tons sold as a result of an extended outage in the prior year; and
- Earnings at our Power Generation segment decreased $1.9 million primarily due to an increase in net income attributable to noncontrolling interests, reflecting a full nine months in 2017 compared to approximately 5.5 months in the same period of the prior year.

The following table summarizes select financial results by operating segment and details significant items (in thousands):

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
Revenue						
Revenue	$373,412	$365,742	$7,670	$1,338,724	$1,205,305	$133,419
Inter-company eliminations	(31,274)	(31,956)	682	(94,605)	(96,119)	1,514
	$342,138	$333,786	$8,352	$1,244,119	$1,109,186	$134,933
Net income (loss) available for common stock						
Electric Utilities	$27,324	$24,181	$3,143	$68,386	$62,625	$5,761
Gas Utilities	(4,329)	(2,939)	(1,390)	41,409	29,975	11,434
Power Generation [a]	6,155	5,642	513	18,017	19,907	(1,890)
Mining	3,477	3,307	170	9,048	6,969	2,079
Oil and Gas [b] [c]	(2,712)	(8,828)	6,116	(7,609)	(35,277)	27,668
	29,915	21,363	8,552	129,251	84,199	45,052
Corporate activities and eliminations [d] [e]	(2,252)	(7,232)	4,980	(2,870)	(29,397)	26,527
Net income available for common stock	$27,663	$14,131	$13,532	$126,381	$54,802	$71,579

(a) Net income available for common stock for the three and nine months ended September 30, 2017 is net of net income attributable to noncontrolling interest of $3.9 million and $11 million, respectively, and $3.8 million and $6.4 million for the three and nine months ended September 30, 2016, respectively.

(b) Net (loss) available for common stock for the three and nine months ended September 30, 2016 included non-cash after-tax impairments of our oil and gas properties of $7.9 million and $33 million, respectively. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) Net (loss) available for common stock for the nine months ended September 30, 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 tax years.

(d) Net (loss) available for common stock for the three and nine months ended September 30, 2017 included incremental, non-recurring acquisition costs, after-tax of $0.2 million and $1.5 million, respectively, as compared to $4.0 million and $24 million for the same periods in the prior year. The three and nine months ended September 30, 2016 also included after-tax internal labor costs attributable to the acquisition of $1.7 million and $7.4 million, respectively.

(e) Net (loss) available for common stock for the nine months ended September 30, 2017 included a net tax benefit of approximately $1.4 million from a carryback claim for specified liability losses involving prior tax years. Net (loss) available for common stock for the nine months ended September 30, 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. See Note 18 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced milder summer weather during the three and nine months ended September 30, 2017 compared to the three and nine months ended September 30, 2016. Cooling degree days for the three and nine months ended September 30, 2017 were both 15% higher than normal, compared to 15% and 26% higher than normal for the same periods in 2016. Compared to the same periods in the prior year, cooling degree days were 5% and 14% lower, respectively. Heating degree days for the three and nine months ended September 30, 2017 were 8% and 11% lower than normal, respectively, compared to 34% and 13% lower than normal for the same periods 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 construct new generation and plans to present the results to the CPUC by year-end.

- 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. The briefing schedule runs through November 2017. The timing of a ruling is uncertain.

- 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 Segment

- 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.

- Gas Utilities experienced milder weather during the non-peak three months ended September 30, 2017 compared to the three months ended September 30, 2016. Heating degree days for the three months ended September 30, 2017 were 22% lower than normal compared to 2% lower than normal for the same period in 2016. For the nine months ended September 30, 2017, Gas Utilities experienced slightly colder weather compared to the nine months ended September 30, 2016. Heating degree days were 12% lower than normal for the nine months ended September 30, 2017 compared to 20% lower than normal for the same period in 2016.

The Gas Utilities also experienced cooler summer temperatures and higher precipitation levels during the three months ended September 30, 2017 than the same period in 2016, which reduced the irrigation load delivered to agricultural customers, primarily in our Nebraska service territory.

Oil and Gas Segment

- On November 1, 2017, our board of directors authorized the sale of all remaining oil and gas assets and the exit of the business. The segment will be reported as discontinued operations beginning with fourth quarter results. The company has retained advisors to support its ongoing property sales efforts and plans to divest all remaining properties by year-end 2018.

- We recently signed agreements to sell our San Juan Basin assets in New Mexico and certain Powder River Basin assets in Wyoming for a combined $28 million. The San Juan Basin transaction is subject to final approval from the

U.S. Bureau of Indian Affairs and U.S. Bureau of Land Management. Both transactions are expected to close by year-end.

- Oil and Gas production volumes decreased 9% and 17% for the three and nine months ended September 30, 2017 compared to the same periods in 2016, respectively. The decrease in production was due to the 2016 sales of non-core properties, and limiting 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. The average hedged price received for natural gas decreased 15% for the three months ended September 30, 2017 and increased 21% for the nine months ended September 30, 2017 compared to the same periods in 2016, respectively. The average hedged price received for oil decreased 11% and 14% for the three and nine months ended September 30, 2017 compared to the same periods in 2016, respectively.

Corporate Activities

- On August 4, 2017, we renewed the ATM equity offering program initiated in March 2016 which reset the size of the ATM equity offering 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 with the exception that the aggregate value increased $100 million.

- 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.

- On July 21, 2017, S&P affirmed Black Hills' credit rating at BBB rating and maintained a Stable outlook.

- On October 4, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and changed its outlook from Negative to Stable, citing successful integration of SourceGas, a low business risk profile focused on utility operations and expected improvement of credit metrics.

Tax Matters - Potential Corporate Tax Reform

President Trump and Congressional Republicans have stated that one of their top priorities is enactment of comprehensive tax reform. On November 2, 2017, the House Ways and Means Committee released its tax reform bill. Significant uncertainty exists as to the ultimate legislation that will be enacted into law. We are evaluating the proposed legislation; any impact on our future results of operations, financial position and cash flows as a result of the potential changes cannot yet be determined and such changes could be material.

Operating Results

A discussion of operating results from our segments and Corporate activities follows.

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.

Gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel and purchased power. Gross margin for our Gas Utilities is calculated as operating revenue less cost of natural 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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue	$183,571	$174,501	$9,070	$528,048	$503,258	$24,790
Total fuel and purchased power	68,733	66,953	1,780	199,398	194,477	4,921
Gross margin	114,838	107,548	7,290	328,650	308,781	19,869
Operations and maintenance	40,204	38,108	2,096	125,302	116,312	8,990
Depreciation and amortization	23,446	21,063	2,383	69,427	62,794	6,633
Total operating expenses	63,650	59,171	4,479	194,729	179,106	15,623
Operating income	51,188	48,377	2,811	133,921	129,675	4,246
Interest expense, net	(12,744)	(12,046)	(698)	(39,049)	(36,676)	(2,373)
Other income (expense), net	649	1,335	(686)	1,579	2,828	(1,249)
Income tax benefit (expense)	(11,769)	(13,485)	1,716	(28,065)	(33,202)	5,137
Net income	$27,324	$24,181	$3,143	$68,386	$62,625	$5,761

Results of Operations for the Electric Utilities for the Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016: Net income available for common stock for the Electric Utilities was $27 million for the three months ended September 30, 2017, compared to Net income available for common stock of $24 million for the three months ended September 30, 2016, as a result of:

Gross margin increased due primarily to a $3.3 million increase in rider revenues primarily related to transmission investment recovery and a $3.0 million return on investment from the Peak View Wind Project.

Operations and maintenance increased primarily due to $1.4 million of higher generation outage and major maintenance expenses for turbine, generator, pulverizer and boiler work as compared to the prior year. Employee costs increased $0.9 million as a result of prior year integration activities and transition expenses charged to the Corporate segment. In addition, operating expenses increased $0.4 million from the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Depreciation and amortization increased primarily due to a higher asset base driven 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 income (expense), net decreased due to reduced AFUDC with lower current year capital spend.

Income tax benefit (expense): The effective tax rate was lower than the prior year due primarily to wind production tax credits related to the Peak View Wind Project.

Results of Operations for the Electric Utilities for the Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016: Net income available for common stock for the Electric Utilities was $68 million for the nine months ended September 30, 2017, compared to Net income available for common stock of $63 million for the nine months ended September 30, 2016, as a result of:

Gross margin increased over the prior year reflecting a $7.5 million return on investment from the Peak View Wind Project, a $6.4 million increase in rider revenues primarily related to transmission investment recovery and a $3.3 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 increase.

Operations and maintenance increased primarily due to $4.2 million of higher employee costs as a result of prior year integration activities and transition expenses charged to the Corporate segment, $2.0 million increase in generation outage and major maintenance expenses with increased scope of work, $1.9 million of higher property taxes with an increased asset base, and $1.3 million of higher operating expenses from the Peak View Wind Project and 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Depreciation and amortization increased primarily due to a higher asset base driven 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 prior year.

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

Income tax benefit (expense): The effective tax rate was lower than the prior year due primarily to wind production tax credits related to the Peak View Wind Project.

Revenue - Electric (in thousands)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Residential:				
South Dakota Electric	$18,020	$17,501	$53,724	$53,057
Wyoming Electric	10,083	9,585	29,571	29,283
Colorado Electric	27,763	27,460	74,722	73,721
Total Residential	55,866	54,546	158,017	156,061
Commercial:				
South Dakota Electric	25,459	25,714	72,608	73,026
Wyoming Electric	16,389	16,306	48,565	47,818
Colorado Electric	26,196	25,907	74,322	72,782
Total Commercial	68,044	67,927	195,495	193,626
Industrial:				
South Dakota Electric	8,149	8,275	24,774	24,540
Wyoming Electric	12,104	11,904	37,737	32,353
Colorado Electric	10,311	9,870	29,072	28,917
Total Industrial	30,564	30,049	91,583	85,810
Municipal:				
South Dakota Electric	1,071	1,053	2,849	2,844
Wyoming Electric	542	543	1,588	1,606
Colorado Electric	3,345	3,299	9,497	8,879
Total Municipal	4,958	4,895	13,934	13,329
Total Retail Revenue - Electric	159,432	157,417	459,029	448,826
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric [(a)]	8,048	4,596	22,593	12,717
Off-system Wholesale:				
South Dakota Electric	4,787	3,984	11,044	11,304
Wyoming Electric	758	924	3,505	3,777
Colorado Electric	387	522	561	1,229
Total Off-system Wholesale	5,932	5,430	15,110	16,310
Other Revenue:				
South Dakota Electric	8,404	5,605	26,193	19,901
Wyoming Electric	794	325	2,333	1,435
Colorado Electric	961	1,128	2,790	4,069
Total Other Revenue	10,159	7,058	31,316	25,405
Total Revenue - Electric	$183,571	$174,501	$528,048	$503,258

(a) Increase for the three and nine months ended September 30, 2017 was primarily due to a new 50 MW power sales agreement effective January 1, 2017.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Quantities Generated and Purchased (in MWh)	2017	2016	2017	2016
Generated —				
Coal-fired:				
South Dakota Electric	423,766	401,231	1,101,291	1,054,264
Wyoming Electric [(d)]	201,824	188,739	562,644	548,513
Total Coal-fired	625,590	589,970	1,663,935	1,602,777
Natural Gas and Oil:				
South Dakota Electric [(a)]	54,466	41,654	75,840	96,649
Wyoming Electric [(a)]	25,567	23,874	39,136	58,944
Colorado Electric	76,432	64,507	134,089	128,397
Total Natural Gas and Oil	156,465	130,035	249,065	283,990
Wind:				
Colorado Electric [(b)]	38,773	10,676	167,429	34,325
Total Wind	38,773	10,676	167,429	34,325
Total Generated:				
South Dakota Electric	478,232	442,885	1,177,131	1,150,913
Wyoming Electric [(a)]	227,391	212,613	601,780	607,457
Colorado Electric [(b)]	115,205	75,183	301,518	162,722
Total Generated	820,828	730,681	2,080,429	1,921,092
Purchased —				
South Dakota Electric [(c)]	357,053	247,097	1,222,864	902,166
Wyoming Electric [(d)]	207,554	215,257	696,229	624,137
Colorado Electric [(b)]	476,084	527,947	1,273,125	1,473,195
Total Purchased	1,040,691	990,301	3,192,218	2,999,498
Total Generated and Purchased:				
South Dakota Electric [(c)]	835,285	689,982	2,399,995	2,053,079
Wyoming Electric	434,945	427,870	1,298,009	1,231,594
Colorado Electric	591,289	603,130	1,574,643	1,635,917
Total Generated and Purchased	1,861,519	1,720,982	5,272,647	4,920,590

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(a) Variances for the three and nine months ended September 30, 2017 compared to the same periods in the prior year are driven primarily by the ability to purchase excess generation in the open market at a lower or higher cost than to generate.

(b) Increase in generation in 2017 is due to the addition of the Peak View Wind Project in November 2016. This generation replaced resources provided by PPAs in 2016, reducing the quantities purchased.

(c) Increase in 2017 is primarily driven by resource needs from a new 50 MW power sales agreement effective January 1, 2017.

(d) Year over year increase for nine months ended September 30, 2017 is primarily driven by new load supporting data centers in Cheyenne, Wyoming.

Quantity Sold (in MWh)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Residential:				
South Dakota Electric	129,616	124,012	386,709	381,616
Wyoming Electric	65,723	63,505	190,087	191,405
Colorado Electric	174,127	176,900	461,641	470,246
Total Residential	369,466	364,417	1,038,437	1,043,267
Commercial:				
South Dakota Electric	212,773	213,276	582,899	592,371
Wyoming Electric	137,169	137,534	398,178	398,414
Colorado Electric	208,033	211,716	566,177	572,062
Total Commercial	557,975	562,526	1,547,254	1,562,847
Industrial:				
South Dakota Electric	109,745	110,220	323,038	320,861
Wyoming Electric [(a)]	182,844	175,188	545,640	468,262
Colorado Electric	114,357	116,073	323,638	329,016
Total Industrial	406,946	401,481	1,192,316	1,118,139
Municipal:				
South Dakota Electric	10,156	9,927	25,865	25,855
Wyoming Electric	2,154	2,201	6,643	6,848
Colorado Electric	35,079	34,507	92,557	91,116
Total Municipal	47,389	46,635	125,065	123,819
Total Retail Quantity Sold	1,381,776	1,375,059	3,903,072	3,848,072
Contract Wholesale:				
Total Contract Wholesale-South Dakota Electric [(b)]	185,723	62,547	537,720	182,087
Off-system Wholesale:				
South Dakota Electric [(c)]	130,825	128,415	388,287	438,852
Wyoming Electric	17,981	18,788	72,517	77,534
Colorado Electric [(c)]	10,619	17,949	16,479	53,644
Total Off-system Wholesale	159,425	165,152	477,283	570,030
Total Quantity Sold:				
South Dakota Electric	778,838	648,397	2,244,518	1,941,642
Wyoming Electric	405,871	397,216	1,213,065	1,142,463
Colorado Electric	542,215	557,145	1,460,492	1,516,084
Total Quantity Sold	1,726,924	1,602,758	4,918,075	4,600,189
Other Uses, Losses or Generation, net [(d)]:				
South Dakota Electric	56,447	41,585	155,477	111,437
Wyoming Electric	29,074	30,654	84,944	89,131

Colorado Electric	49,074	45,985	114,151	119,833
Total Other Uses, Losses and Generation, net	134,595	118,224	354,572	320,401
Total Energy	1,861,519	1,720,982	5,272,647	4,920,590

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(a) Year over year increases are driven by new load supporting data centers in Cheyenne, Wyoming.

(b) Increase for the three and nine months ended September 30, 2017 was primarily due to a new 50 MW power sales agreement effective January 1, 2017.

(c) Decrease in 2017 was primarily driven by commodity prices that impacted power marketing sales.

(d) Includes company uses, line losses, and excess exchange production.

Degree Days	Three Months Ended September 30, 2017			2016	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	202	(10)%	25%	161	(23)%
Wyoming Electric	292	(4)%	39%	210	(19)%
Colorado Electric	87	(11)%	335%	20	(77)%
Combined [(a)]	168	(8)%	57%	107	(34)%
Cooling Degree Days:					
South Dakota Electric	595	11 %	29%	460	(18)%
Wyoming Electric	388	30 %	8%	358	19 %
Colorado Electric	784	14 %	(19)%	968	33 %
Combined [(a)]	640	15 %	(5)%	673	15 %

Degree Days	Nine Months Ended September 30, 2017			2016	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	4,242	(5)%	10%	3,844	(13)%
Wyoming Electric	4,186	(11)%	2%	4,120	(12)%
Colorado Electric	2,773	(17)%	(2)%	2,821	(15)%
Combined [(a)]	3,559	(11)%	4%	3,430	(13)%
Cooling Degree Days:					
South Dakota Electric	709	12 %	10%	646	(3)%
Wyoming Electric	429	23 %	(7)%	460	31 %
Colorado Electric	1,027	15 %	(23)%	1,337	40 %
Combined [(a)]	798	15 %	(14)%	926	26 %

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(a) Combined actuals are calculated based on the weighted average number of total customers by state.

Electric Utilities Power Plant Availability	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Coal-fired plants [(a)]	98.3%	94.8%	88.1%	88.0%
Natural gas fired plants and Other plants	94.6%	98.4%	95.8%	97.0%
Wind [(b)]	91.0%	99.1%	92.0%	99.2%
Total availability	95.5%	97.1%	93.0%	93.7%

Wind capacity factor	23.6%	33.5%	34.3%	36.1%

(a) Both the nine months ended September 30, 2017 and 2016 included outages. 2017 included planned outages at Neil Simpson II, Wyodak and Wygen II, and 2016 included a planned outage at Wygen III and an extended planned outage at Wyodak.

(b) 2017 is lower than the prior year primarily due to the addition of the Peak View Wind Project for which 2017 is the first year of commercial operation.

Gas Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$126,865	$123,699	$3,166	$618,924	$515,963	$102,961
Other — non-regulated services	16,029	17,746	(1,717)	55,327	47,916	7,411
Total revenue	142,894	141,445	1,449	674,251	563,879	110,372
Cost of sales						
Natural gas — regulated	33,376	29,330	4,046	255,410	202,244	53,166
Other — non-regulated services	11,917	12,400	(483)	33,615	25,755	7,860
Total cost of sales	45,293	41,730	3,563	289,025	227,999	61,026
Gross margin	97,601	99,715	(2,114)	385,226	335,880	49,346
Operations and maintenance	65,390	64,921	469	201,105	179,845	21,260
Depreciation and amortization	20,937	21,193	(256)	62,658	57,096	5,562
Total operating expenses	86,327	86,114	213	263,763	236,941	26,822
Operating income	11,274	13,601	(2,327)	121,463	98,939	22,524
Interest expense, net	(19,527)	(21,267)	1,740	(58,919)	(53,858)	(5,061)
Other income (expense), net	(294)	(418)	124	(342)	(28)	(314)
Income tax benefit (expense)	4,218	5,128	(910)	(20,686)	(15,065)	(5,621)
Net income (loss)	(4,329)	(2,956)	(1,373)	41,516	29,988	11,528
Net (income) loss attributable to noncontrolling interest	—	17	(17)	(107)	(13)	(94)
Net income (loss) available for common stock	$(4,329)	$(2,939)	$(1,390)	$41,409	$29,975	$11,434

Results of Operations for the Gas Utilities for the Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016: Net loss available for common stock for the Gas Utilities was $(4.3) million for the three months ended September 30, 2017, compared to Net loss available for common stock of $(3.0) million for the three months ended September 30, 2016, as a result of:

Gross margin decreased primarily due to a $3.4 million weather impact from cooler summer temperatures and higher precipitation driving lower irrigation load to agriculture customers in our Nebraska Gas service territory as compared to the same period in the prior year. This is partially offset by gas utilities' customer growth and higher rider revenue.

Operations and maintenance increased primarily due to $1.2 million higher employee related expenses as a result of prior year integration activities and transition expenses charged to the Corporate segment, partially offset by lower pension expenses.

Depreciation and amortization was comparable to the same period in the prior year.

Interest expense, net decreased primarily due to the August 2016 refinancing of the debt assumed in the SourceGas Acquisition.

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

Income tax benefit (expense): The 2017 effective tax rate is lower than 2016 due to increased flow-through benefits and no changes to uncertain tax positions as compared to 2016.

Results of Operations for the Gas Utilities for the Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016: Net income available for common stock for the Gas Utilities was $41 million for the nine months ended September 30, 2017, compared to Net income available for common stock of $30 million for the nine months ended September 30, 2016, as a result of:

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 nine months of SourceGas results as compared to approximately 7.5 months in 2016. This is partially offset by lower irrigation loads delivered to agriculture customers primarily in the Nebraska service territory due to cooler summer temperatures and higher precipitation in the third quarter of 2017.

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities, reflecting a full nine months of results in 2017 as compared to approximately 7.5 months in 2016. In addition, employee related expenses increased $5.2 million for the Black Hills legacy gas utilities as a result of prior year integration activities and transition expenses charged to the Corporate segment. 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 income (expense), net was comparable to the same period in the prior year.

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

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	Three Months Ended September 30,		Nine Months Ended September 30,	
Revenue (in thousands) [a]	2017	2016	2017	2016
Residential:				
Arkansas	$9,085	$8,201	$57,992	$33,778
Colorado	12,911	12,144	80,351	65,285
Nebraska [b]	12,622	12,259	72,965	69,132
Iowa	10,314	9,694	60,618	57,328
Kansas	8,128	7,760	44,309	39,428
Wyoming [b]	4,744	4,895	28,172	23,663
Total Residential	$57,804	$54,953	$344,407	$288,614
Commercial:				
Arkansas	$5,281	$4,123	$30,465	$16,652
Colorado	4,893	4,971	29,967	23,107
Nebraska	2,994	3,123	20,567	19,462
Iowa	3,425	3,144	24,522	22,617
Kansas	2,672	2,298	14,695	12,558
Wyoming	2,101	2,315	13,940	11,495
Total Commercial	$21,366	$19,974	$134,156	$105,891
Industrial:				
Arkansas	$1,801	$1,463	$5,382	$3,071
Colorado	906	808	1,588	1,340
Nebraska	158	143	363	330
Iowa	119	189	1,158	1,014
Kansas	5,734	5,204	7,716	7,793
Wyoming	754	692	2,492	2,349
Total Industrial	$9,472	$8,499	$18,699	$15,897
Transportation:				
Arkansas	$2,335	$1,997	$7,750	$5,730
Colorado	738	766	2,940	2,531
Nebraska [b] [c]	20,343	23,222	54,202	49,147
Iowa	967	970	3,557	3,525
Kansas	1,598	1,736	4,851	5,134
Wyoming [b]	4,387	4,245	18,849	14,382
Total Transportation	$30,368	$32,936	$92,149	$80,449

Revenue (in thousands) (continued)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Transmission:				
Arkansas	$448	$19	$1,660	$44
Colorado	4,014	3,572	17,778	12,334
Wyoming	1,211	1,209	3,712	3,386
Total Transmission	$5,673	$4,800	$23,150	$15,764
Other Sales Revenue:				
Arkansas	$218	$398	$880	$1,687
Colorado	208	315	687	770
Nebraska	937	912	2,724	2,587
Iowa	96	96	357	409
Kansas	494	582	936	3,215
Wyoming	229	234	779	680
Total Other Sales Revenue	$2,182	$2,537	$6,363	$9,348
Total Regulated Revenue	$126,865	$123,699	$618,924	$515,963
Non-regulated Services	16,029	17,746	55,327	47,916
Total Revenue	$142,894	$141,445	$674,251	$563,879

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(a) Certain prior year revenue classes have been revised to conform to current year presentation; total revenue did not change.

(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

(c) Decrease for the three months ended September 30, 2017 is primarily driven by lower irrigation load in 2017 compared to the prior year.

Gross Margin (in thousands) [(a)]	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Residential:				
Arkansas	$6,934	$6,735	$38,020	$24,116
Colorado	7,533	7,235	33,784	28,531
Nebraska [(b)]	9,333	9,214	38,383	37,634
Iowa	8,430	8,252	31,442	30,848
Kansas	6,033	5,872	24,031	22,401
Wyoming [(b)]	3,749	3,863	16,596	15,164
Total Residential	$42,012	$41,171	$182,256	$158,694
Commercial:				
Arkansas	$2,904	$2,551	$16,053	$9,595
Colorado	2,198	2,385	10,660	8,612
Nebraska	1,606	1,652	7,952	7,865

Iowa	1,930	1,894	8,504	8,351
Kansas	1,371	1,289	5,846	5,300
Wyoming	1,088	1,217	5,916	5,596
Total Commercial	$11,097	$10,988	$54,931	$45,319

Gross Margin (in thousands) (continued)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Industrial:				
Arkansas	$566	$582	$1,727	$1,268
Colorado	292	326	513	594
Nebraska	57	54	134	149
Iowa	33	40	169	127
Kansas	1,052	986	1,638	1,754
Wyoming	157	163	484	513
Total Industrial	$2,157	$2,151	$4,665	$4,405
Transportation:				
Arkansas	$2,335	$1,997	$7,750	$5,730
Colorado	738	539	2,940	2,293
Nebraska (b) (c)	20,343	23,222	54,202	49,147
Iowa	967	970	3,557	3,525
Kansas	1,598	1,736	4,851	5,134
Wyoming (b)	4,387	4,245	18,849	14,382
Total Transportation	$30,368	$32,709	$92,149	$80,211
Transmission:				
Arkansas	$448	$19	$1,660	$44
Colorado	4,014	3,572	17,778	12,334
Wyoming	1,211	1,209	3,712	3,362
Total Transmission	$5,673	$4,800	$23,150	$15,740
Other Sales Margins:				
Arkansas	$218	$398	$880	$1,688
Colorado	208	315	687	770
Nebraska	937	912	2,724	2,586
Iowa	96	96	357	409
Kansas	494	595	936	3,217
Wyoming	229	234	779	680
Total Other Sales Margins	$2,182	$2,550	$6,363	$9,350
Total Regulated Gross Margin	$93,489	$94,369	$363,514	$313,719
Non-regulated Services	4,112	5,346	21,712	22,161
Total Gross Margin	$97,601	$99,715	$385,226	$335,880

(a) Certain prior year revenue classes have been revised to conform to current year presentation.

(b) Change in prior year due to reclassification of Residential Choice customers from Residential to Transportation class.

(c) Decrease for the three months ended September 30, 2017 is primarily driven by lower irrigation load in 2017 compared to the prior year.

Gas Utilities Quantities Sold and Transportation (in Dth) [(a)]	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Residential:				
Arkansas	530,573	531,564	5,058,717	3,277,167
Colorado	1,114,728	1,067,081	9,385,555	8,012,982
Nebraska	747,053	719,880	7,496,171	7,375,926
Iowa	544,429	478,158	6,691,008	6,744,086
Kansas	431,594	416,971	4,066,531	4,071,723
Wyoming	314,567	335,772	3,354,432	2,951,579
Total Residential	3,682,944	3,549,426	36,052,414	32,433,463
Commercial:				
Arkansas	586,224	526,937	3,630,598	2,377,038
Colorado	479,409	539,304	3,700,032	2,973,962
Nebraska	317,867	384,546	2,764,350	2,800,616
Iowa	438,185	423,084	3,729,944	3,725,512
Kansas	284,647	220,650	1,831,946	1,771,050
Wyoming	339,515	382,503	2,454,248	2,194,570
Total Commercial	2,445,847	2,477,024	18,111,118	15,842,748
Industrial:				
Arkansas	304,556	305,910	914,235	651,815
Colorado	234,770	212,997	357,806	345,126
Nebraska	33,050	29,531	64,960	62,243
Iowa	30,136	52,092	225,464	243,902
Kansas	1,931,919	1,645,891	2,483,575	2,575,314
Wyoming	187,742	185,299	644,052	673,366
Total Industrial	2,722,173	2,431,720	4,690,092	4,551,766
Total Quantities Sold	8,850,964	8,458,170	58,853,624	52,827,977
Transportation:				
Arkansas	2,528,754	2,225,478	8,628,581	5,774,791
Colorado	1,282,746	668,591	5,713,315	2,267,404
Nebraska [(b)]	13,522,759	15,123,440	42,476,603	38,723,621
Iowa	4,333,161	4,394,260	14,826,265	14,860,343
Kansas	4,622,069	4,598,060	12,593,545	11,646,066
Wyoming	4,287,998	4,707,013	18,076,356	17,194,446
Total Transportation	30,577,487	31,716,842	102,314,665	90,466,671
Total Quantities Sold and Transportation	39,428,451	40,175,012	161,168,289	143,294,648

(a) Certain prior year revenue classes have been revised to conform to current year presentation.

(b) Decrease for the three months ended September 30, 2017 is primarily driven by lower irrigation load in 2017 compared to the prior year.

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Approximately 70% of our Gas Utilities’ revenue and margins are expected in the first and fourth quarters of each year. Therefore, revenue for, and certain expenses of, these operations fluctuate significantly among quarters. Depending upon the geographic location in which our Gas Utilities operate, the winter heating season begins around November 1 and ends around March 31.

Degree Days	Three Months Ended September 30, 2017			2016	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a] [d]	15	(66)%	67%	9	(79)%
Colorado	187	(13)%	22%	153	(29)%
Nebraska	66	(40)%	(65)%	191	74%
Iowa	90	(35)%	32%	68	(51)%
Kansas [a]	37	(32)%	42%	26	(54)%
Wyoming	307	1%	(2)%	314	3%
Combined [b] [d]	117	(22)%	(20)%	146	(2)%

Degree Days	Nine Months Ended September 30, 2017			2016	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year [c]	Actual	Variance from 30-Year Average
Arkansas [a] [d]	1,826	(26)%	52%	1,198	(52)%
Colorado	3,541	(14)%	(4)%	3,670	(6)%
Nebraska	3,280	(13)%	(1)%	3,312	(13)%
Iowa	3,641	(13)%	(4)%	3,783	(11)%
Kansas [a]	2,584	(13)%	—%	2,596	(13)%
Wyoming	4,468	(5)%	3%	4,334	(7)%
Combined [b] [d]	3,521	(12)%	10%	3,215	(20)%

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(a) Arkansas has a weather normalization mechanism in effect during the months of November through April for customers with residential and business rate schedules. Kansas Gas has an approved weather normalization mechanism within its residential and business rate structure, which minimizes weather impact on gross margins. The weather normalization mechanism in Arkansas differs from that in Kansas in that it only uses one location to calculate the weather, compared to Kansas, which uses multiple locations. The weather normalization mechanism in Arkansas minimizes weather impact, but does not eliminate the impact.

(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) The actual variance in heating degree days for the nine months ended September 30, 2017 compared to prior year is not a reasonable measurement of weather impacts due to the exclusion of the pre-acquisition heating degree days for the SourceGas utilities in Arkansas, Colorado, Nebraska and Wyoming. These utilities were acquired on February 12, 2016.

(d) In 2016, the 30-year weather average for Arkansas was calculated on average actual daily temperatures. To conform to current year comparisons to normal, the 2016 variances for Arkansas compared to normal and the 2016 combined variance compared to normal have been updated for both the three and nine months ended September 30, 2016.

Regulatory Matters

For more information on enacted regulatory provisions with respect to the states in which our Utilities operate, see Part I, Items 1 and 2 of our 2016 Annual Report on Form 10-K filed with the SEC.

Electric Utilities Rates and Rate Activity

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 six-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, will also be amortized over the moratorium period. The change in amortization periods for these costs will increase annual amortization expense by approximately $2.7 million.

The June 16, 2017 settlement had no impact to base rates. The following table illustrates information about certain enacted regulatory provisions with respect to South Dakota Electric:

Subsidiary	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters	Percentage of Power Marketing Profit Shared with Customers
South Dakota Electric	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TCA, Energy Efficiency Cost Recovery/DSM	70%

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. The 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. 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. This application was denied by the CPUC on June 9, 2017. We subsequently filed an appeal of this decision with Denver District Court on July 10, 2017. The briefing schedule runs through November 2017. The timing of a ruling is uncertain.

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 Rates and Rate Activity

RMNG Rate Review

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.

The following table summarizes recent activity of certain state and federal rate reviews, riders and surcharges (dollars in millions):

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Arkansas Stockton Storage [a]	Gas - storage	11/2016	1/2017	$ 2.6	$ 2.6
Arkansas MRP/ARMRP [b]	Gas	9/2017	9/2017	$ 2.7	$ 2.7
Kansas Gas [c]	Gas	5/2017	6/2017	$ 1.4	$ 1.4
RMNG [d]	Gas - transmission and storage	11/2016	1/2017	$ 2.9	$ 2.9
Nebraska Gas Dist. [e]	Gas	10/2016	2/2017	$ 6.5	$ 6.5

(a) On November 15, 2016, Arkansas Gas filed for the recovery of the Stockton Storage revenue requirement through the Stockton Storage Acquisition Rates regulatory mechanism with the rider effective January 1, 2017. This recovery mechanism was initially approved on October 15, 2015 for the Stockton Storage acquisition.

(b) On September 1, 2017, Arkansas Gas filed for recovery of $2.2 million related to projects for the replacement of eligible mains (MRP) and the recovery of $0.5 million related to projects for the relocation of certain at risk meters (ARMRP). Pursuant to the Arkansas Gas Tariff, the filed rates went into effect on the date of the filing.

(c) On February 21, 2017, Kansas Gas filed with the KCC requesting recovery of $1.4 million, which includes $0.6 million of new revenue related to the Gas System Reliability Surcharge rider (“GSRS”). This GSRS filing was approved by the KCC on May 23, 2017 and went into effect on June 1, 2017.

(d) On November 3, 2016, RMNG filed with the CPUC requesting recovery of $2.9 million, which includes $1.2 million of new revenue related to system safety and integrity expenditures on projects for the period of 2014 through 2017. This SSIR request was approved by the CPUC in December 2016, and went into effect on January 1, 2017.

(e) On October 3, 2016, Nebraska Gas Dist. filed with the NPSC requesting recovery of $6.5 million, which includes $1.7 million of new 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 2017, and went into effect on February 1, 2017.

Power Generation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue [a]	$22,927	$23,337	$ (410)	$68,289	$68,359	$(70)
Operations and maintenance	7,646	7,465	181	24,228	24,155	73
Depreciation and amortization [a]	1,036	996	40	3,312	3,080	232
Total operating expense	8,682	8,461	221	27,540	27,235	305
Operating income	14,245	14,876	(631)	40,749	41,124	(375)
Interest expense, net	(724)	(409)	(315)	(2,015)	(1,343)	(672)
Other (expense) income, net	(5)	(9)	4	(36)	(5)	(31)
Income tax (expense) benefit	(3,426)	(5,046)	1,620	(10,114)	(13,467)	3,353
Net income	10,090	9,412	678	28,584	26,309	2,275

Net income attributable to noncontrolling interest	(3,935)	(3,770)	(165)	(10,567)	(6,402)	(4,165)
Net income available for common stock	$6,155	$5,642	$ 513	$18,017	$19,907	$(1,890)

(a) The generating facility located in Pueblo, Colorado is accounted for as a capital lease under GAAP; as such, revenue and depreciation expense are impacted by the accounting for this lease. Under the lease, the original cost of the facility is recorded at Colorado Electric and is being depreciated by Colorado Electric for segment reporting purposes.

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 three and nine months ended September 30, 2017, was reduced by $3.9 million and $11 million, respectively, and reduced by $3.8 million and $6.4 million for the three and nine months ended September 30, 2016, respectively, attributable to this noncontrolling interest.

Results of Operations for Power Generation for the Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016: Net income available for common stock for the Power Generation segment was $6.2 million for the three months ended September 30, 2017, compared to Net income available for common stock of $5.6 million for the same period in 2016. Revenue and operating expenses were comparable to the same period in the prior year. The variance to the prior year was driven by a lower 2017 effective tax rate compared to 2016 due to the greater impact of minority interest and higher 2016 adjustments to the filed tax return.

Results of Operations for Power Generation for the Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016: Net income available for common stock for the Power Generation segment was $18 million for the nine months ended September 30, 2017, compared to Net income available for common stock of $20 million for the same period in 2016. Revenue and operating expenses were comparable to the same period in the prior year. The variance to the prior year was due to Black Hills Colorado IPP going from a single member LLC, wholly owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9% of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision is not recorded. Net income attributable to noncontrolling interest also increased by $4.2 million as a result of the noncontrolling interest sale in April 2016.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Quantities Sold, Generated and Purchased (MWh) [(a)]				
Sold				
Black Hills Colorado IPP [(b)]	256,895	327,793	725,919	972,113
Black Hills Wyoming [(c)]	163,690	167,670	476,659	476,677
Total Sold	420,585	495,463	1,202,578	1,448,790
Generated				
Black Hills Colorado IPP [(b)]	256,895	327,793	725,919	972,113
Black Hills Wyoming [(c)]	140,081	142,388	407,775	401,292
Total Generated	396,976	470,181	1,133,694	1,373,405
Purchased				
Black Hills Colorado IPP	—	—	—	—
Black Hills Wyoming [(c)]	20,246	23,558	52,463	68,797
Total Purchased	20,246	23,558	52,463	68,797

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(a) Company uses and losses are not included in the quantities sold, generated, and purchased.

(b) Decrease from the prior year is a result of the 2017 impact of Colorado Electric's wind generation replacing natural-gas generation.

(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. MWh sold may not equal MWh generated and purchased due to a dispatch agreement Black Hills Wyoming has with South Dakota Electric to cover energy imbalances.

The following table provides certain operating statistics for our plants within the Power Generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Contracted power plant fleet availability:				
Coal-fired plant	97.1%	98.7%	95.8%	94.1%
Natural gas-fired plants	99.2%	99.1%	99.1%	99.2%
Total availability	98.7%	99.0%	98.3%	97.9%

Mining

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue	$17,493	$16,820	$ 673	$48,985	$44,149	$4,836
Operations and maintenance	11,235	10,465	770	32,162	29,186	2,976
Depreciation, depletion and amortization	2,004	2,342	(338)	6,231	7,269	(1,038)
Total operating expenses	13,239	12,807	432	38,393	36,455	1,938
Operating income	4,254	4,013	241	10,592	7,694	2,898
Interest (expense) income, net	(47)	(100)	53	(146)	(283)	137
Other income, net	567	559	8	1,644	1,625	19
Income tax benefit (expense)	(1,297)	(1,165)	(132)	(3,042)	(2,067)	(975)
Net income	$3,477	$3,307	$ 170	$9,048	$6,969	$2,079

The following table provides certain operating statistics for our Mining segment (in thousands, except for Revenue per ton):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Tons of coal sold	1,151	1,106	3,127	2,722
Cubic yards of overburden moved [(a)]	2,316	2,065	6,381	5,516
Revenue per ton	$15.20	$15.20	$15.67	$16.21

(a) Increase is driven by mining in areas with more overburden than in the prior year as well as higher production.

Results of Operations for Mining for the Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016: Net income available for common stock for the Mining segment was $3.5 million for the three months ended September 30, 2017, compared to Net income available for common stock of $3.3 million for the same period in 2016 as a result of:

Revenue increased due to a 4% increase in tons sold, with comparable pricing to the same period last year. The increased tons sold were driven primarily by Wyodak plant generating requirements. During the current period, approximately 47% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to increased overburden removal and higher royalties and production taxes on increased revenues.

Depreciation, depletion and amortization decreased primarily due to a reduction in asset retirement obligation costs.

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

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

Income tax benefit (expense): The effective tax rate is comparable to the same period last year.

Results of Operations for Mining for the Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016: Net income available for common stock for the Mining segment was $9.0 million for the nine months ended September 30, 2017, compared to Net income available for common stock of $7.0 million for the same period in 2016 as a result of:

Revenue increased due to a 15% increase in tons sold, partially offset by a 3% decrease in price per ton sold. The increased tons sold were driven primarily by an 11-week outage at the Wyodak plant in the prior year. The decrease in price per ton sold was driven by higher volumes sold under fixed price contracts. During the current period, approximately 46% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to increased overburden removal and higher royalties and production taxes on increased revenues.

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

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

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

Income tax benefit (expense): The effective tax rate increased reflecting a prior year tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
	(in thousands)					
Revenue	$6,527	$9,639	$(3,112)	$19,151	$25,660	$(6,509)
Operations and maintenance	6,076	7,592	(1,516)	20,385	24,539	(4,154)
Depreciation, depletion and amortization	2,391	3,483	(1,092)	6,300	11,415	(5,115)
Impairment of long-lived assets	—	12,293	(12,293)	—	52,286	(52,286)
Total operating expenses	8,467	23,368	(14,901)	26,685	88,240	(61,555)
Operating (loss)	(1,940)	(13,729)	11,789	(7,534)	(62,580)	55,046
Interest income (expense), net	(1,269)	(1,295)	26	(3,459)	(3,529)	70
Other income (expense), net	(3)	16	(19)	14	85	(71)
Income tax benefit (expense)	500	6,180	(5,680)	3,370	30,747	(27,377)
Net (loss)	$(2,712)	$(8,828)	$6,116	$(7,609)	$(35,277)	$27,668

Results of Operations for Oil and Gas for the Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016: Net loss available for common stock for the Oil and Gas segment was $(2.7) million for the three months ended September 30, 2017, compared to Net loss available for common stock of $(8.8) million for the same period in 2016 as a result of:

Revenue decreased primarily due to a 9% production decrease compared to the same period in the prior year. Natural gas production decreased primarily due to the 2016 sales of non-core properties, and the intentional limiting of gas production to the minimum daily quantities required to meet contractual processing commitments in the Piceance Basin. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016. The average hedged price received for crude oil sold decreased 11%. The average hedged price received for natural gas sold decreased by 15%.

Operations and maintenance decreased primarily due to lower employee costs and lower production and ad valorem taxes on lower revenue.

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

Impairment of long-lived assets represents a prior year non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The prior year ceiling test write-down of $12 million used a trailing 12 month average NYMEX natural gas price of $2.28 per Mcf, adjusted to $1.03 per Mcf at the wellhead, and $41.68 per barrel for crude oil, adjusted to $35.88 per barrel at the wellhead.

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

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

Income tax (expense) benefit: Each period represents a tax benefit. The current period effective tax rate is lower due primarily to a reduction to the marginal well credit compared to the same period last year.

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Results of Operations for Oil and Gas for the Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016: Net loss available for common stock for the Oil and Gas segment was $(7.6) million for the nine months ended September 30, 2017, compared to Net loss available for common stock of $(35) million for the same period in 2016 as a result of:

Revenue decreased primarily due to a 17% production decrease compared to the same period in the prior year. Natural gas production decreased primarily due to the 2016 sales of non-core properties and the intentional limiting of gas production to the minimum daily quantities required to meet contractual processing commitments in the Piceance Basin. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016. The average hedged price received for crude oil sold decreased 14%. The lower production volumes and crude oil pricing were partially offset by a 21% increase in the average hedged price received for natural gas sold.

Operations and maintenance decreased primarily due to lower employee costs and lower production and ad valorem taxes on lower revenue.

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

Impairment of long-lived assets represents a prior year non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The prior year write down of $52 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $38 million. The ceiling test write-down for the nine months ended September 30, 2016 used an average NYMEX natural gas price of $2.28 per Mcf, adjusted to $1.03 per Mcf at the well head, and $41.68 per barrel for crude oil, adjusted to $35.88 per barrel at the wellhead.

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

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

Income tax (expense) benefit: Each period represents a tax benefit. The effective tax rate for the nine months ended September 30, 2016 reflects 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 were 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.

The following tables provide certain operating statistics for our Oil and Gas segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Production:				
Bbls of oil sold	45,240	89,569	139,642	263,788
Mcf of natural gas sold	2,379,189	2,426,892	6,392,999	7,148,952
Bbls of NGL sold	30,810	27,640	82,539	105,535
Mcf equivalent sales	2,835,487	3,130,147	7,726,083	9,364,891

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016

Average price received: [a]				
Oil/Bbl	$50.22	$56.64	$46.95	$54.38
Gas/Mcf	$1.39	$1.63	$1.55	$1.28
NGL/Bbl	$21.79	$11.31	$19.99	$10.95
Depletion expense/Mcfe	$0.52	$0.81	$0.46	$0.86

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(a) Net of hedge settlement gains and losses.

The following is a summary of certain average operating expenses per Mcfe:

	Three Months Ended September 30, 2017				Three Months Ended September 30, 2016			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total
San Juan	$1.60	$ 1.04	$ 0.36	$3.00	$1.69	$ 1.19	$ 0.38	$3.26
Piceance	0.20	1.65	0.06	1.91	0.24	1.84	0.16	2.24
Powder River	1.78	—	0.68	2.46	1.89	—	0.20	2.09
Williston	—	—	—	—	0.84	—	1.64	2.48
All other properties	1.00	—	0.28	1.28	0.30	—	0.22	0.52
Total weighted average	$0.75	$ 1.25	$ 0.22	$2.22	$0.84	$ 1.19	$ 0.33	$2.36

	Nine Months Ended September 30, 2017				Nine Months Ended September 30, 2016			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total
San Juan	$1.67	$ 1.11	$ 0.38	$3.16	$1.65	$ 1.11	$ 0.31	$3.07
Piceance	0.42	1.83	0.05	2.30	0.31	1.86	0.13	2.30
Powder River	2.30	—	0.72	3.02	2.52	—	0.45	2.97
Williston	—	—	—	—	1.22	—	1.02	2.24
All other properties	1.39	—	0.30	1.69	0.37	—	0.12	0.49
Total weighted average	$1.03	$ 1.34	$ 0.23	$2.60	$1.00	$ 1.18	$ 0.27	$2.45

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(a) These costs include both third-party costs and operations costs.

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, while 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.

We have a ten-year gas gathering and processing contract for our natural gas production in the Piceance Basin which became effective in March of 2014. This take-or-pay contract requires us to pay a fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. Our gathering, compression and processing costs on a per Mcfe basis, as shown in the table above, will be higher in periods when we are not meeting the minimum contract requirements.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016: Net loss available for common stock for Corporate was $(2.3) million for the three months ended September 30, 2017, compared to Net loss available for common stock of $(7.2) million for the three months ended September 30, 2016. The variance from the prior year was primarily due to higher corporate expenses incurred in the prior year related to the SourceGas Acquisition. The third quarter of 2017 included approximately $0.2 million of non-recurring after-tax acquisition and transition costs compared to approximately $4.0 million of after-tax non-recurring acquisition and transition costs in the third quarter of 2016. The third quarter of 2016 included $1.7 million of after-tax internal labor related to the SourceGas Acquisition that otherwise would have been charged to other business segments and also included lower income tax expense compared to the third quarter of 2017.

Results of Operations for Corporate activities for the Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016: Net loss available for common stock for Corporate was $(2.9) million for the nine months ended September 30, 2017, compared to Net loss available for common stock of $(29) million for the nine months ended September 30, 2016. The variance from the prior year was primarily due to higher corporate expenses incurred in the prior year related to the SourceGas Acquisition. Current year corporate expenses included approximately $1.5 million of after-tax non-recurring acquisition and transition costs, compared to a total of approximately $24 million of after-tax non-recurring acquisition and transition costs and approximately $7.4 million of after-tax internal labor related to the SourceGas Acquisition that otherwise would have been charged to other business segments. During the nine months ended September 30, 2017, we recognized a tax benefit of approximately $1.4 million tax benefit from a carryback claim for specified liability losses involving prior years. The same period in the prior year included a tax benefit of approximately $4.4 million recognized 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.

Critical Accounting Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2016 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting estimates, see Part II, Item 7 of our 2016 Annual Report on Form 10-K.

Liquidity and Capital Resources

OVERVIEW

Our Company requires significant cash to support and grow our business. 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.

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, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

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 September 30, 2017, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts.

Cash Flow Activities

The following table summarizes our cash flows for the nine months ended September 30 (in thousands):

Cash provided by (used in):	2017	2016	Increase (Decrease)
Operating activities	$319,430	$209,201	$110,229
Investing activities	$(256,388)	$(1,459,196)	$1,202,808
Financing activities	$(63,112)	$840,948	$(904,060)

Year-to-Date 2017 Compared to Year-to-Date 2016

Operating Activities

Net cash provided by operating activities was $319 million for the nine months ended September 30, 2017, compared to net cash provided by operating activities of $209 million for the same period in 2016 for a variance of $110 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $65 million higher for the nine months ended September 30, 2017 compared to the same period in the prior year;

- Net cash outflows from changes in operating assets and liabilities were $17 million for the nine months ended September 30, 2017, compared to net cash outflows of $44 million in the same period in the prior year. This $27 million variance was primarily due to:

Cash outflows decreased due to an increase in cash inflows of approximately $14 million for the nine months ended September 30, 2017 primarily as a result of changes in our accounts receivable, partially offset by higher natural gas in storage for the nine months ended September 30, 2017 compared to the same period in the prior year;

Cash outflows decreased by approximately $16 million as a result of changes in accounts payable and accrued liabilities driven by changes in working capital requirements, primarily related to acquisition and transaction costs that took place in the prior year;

Cash outflows increased by approximately $3.3 million as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts on working capital compared to the same period in the prior year;

- Net cash outflows decreased by approximately $29 million as a result of a prior year interest rate settlement; and

- Net cash outflows increased by $14 million due to additional pension contributions made in the current year.

Investing Activities

Net cash used in investing activities was $256 million for the nine months ended September 30, 2017, compared to net cash used in investing activities of $1.5 billion for the same period in 2016 for a variance of $1.2 billion. This variance was primarily due to:

- The prior year’s cash outflows included $1.124 billion for the acquisition of SourceGas, net of $760 million of long term debt assumed (see Note 2 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K for more details); and

- Capital expenditures of approximately $256 million for the nine months ended September 30, 2017 compared to $334 million for the nine months ended September 30, 2016. The variance to the prior year was due primarily to higher prior year capital expenditures at our Electric Utilities primarily from generation investments at Colorado Electric, partially offset by higher current year capital expenditures at our Gas Utilities.

Financing Activities

Net cash used in financing activities for the nine months ended September 30, 2017 was $63 million, compared to $841 million of net cash provided by financing activities for the same period in 2016 for a variance of $904 million. This variance was primarily driven by:

- 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, $104 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 Colorado IPP that took place in the prior year;

- Net short-term borrowings increased by $130 million primarily due to CP borrowings used to pay down long-term debt;

- Proceeds from common stock decreased by approximately $104 million due to prior year stock issuances under our ATM equity offering program;

- Distributions to noncontrolling interests increased by $8.4 million compared to the prior year;

- Increased dividend payments of approximately $6.1 million; and

- Lower other financing activities of approximately $10 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.

Dividends

Dividends paid on our common stock totaled $71 million for the nine months ended September 30, 2017, or $0.445 per share per quarter. On November 1, 2017, our board of directors declared a quarterly dividend of $0.475 per share payable December 1, 2017, which brings our total dividend for 2017 to $1.81 per share. The amount of any future cash dividends to be declared and paid, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

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 September 30, 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 September 30, 2017	CP Program Borrowings at September 30, 2017	Letters of Credit at September 30, 2017	Available Capacity at September 30, 2017
Revolving Credit Facility	August 9, 2021	$ 750	$ —	$ 225	$ 25	$ 500

The weighted average interest rate on CP Program borrowings at September 30, 2017 was 1.46%. Revolving Credit Facility and CP Program financing activity for the nine months ended September 30, 2017 was (dollars in millions):

	For the Nine Months Ended September 30, 2017
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$ 238
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances)	$ 97
Average amount outstanding - commercial paper (based on daily outstanding balances) [(a)]	$ 107
Average amount outstanding - revolving credit facility (based on daily outstanding balances) [(a)]	$ 55

Weighted average interest rates - commercial paper [(a)]	1.28	%
Weighted average interest rates - revolving credit facility [(a)]	2.07	%

(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 September 30, 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.

Financing Activities

Financing activities for the nine months ended September 30, 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 initiated in 2016 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.

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 a one-to-two year extension of our Revolving Credit Facility and CP program to be completed in 2018; and

- Evaluating refinancing options for term loan and short-term borrowings under our Revolving Credit Facility and CP program.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming 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 subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. 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. 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 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 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. As of September 30, 2017, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

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 meet certain financial covenants. The only financial covenant under our Revolving Credit Facility and existing term loans is a Consolidated Indebtedness to Capitalization Ratio, which requires us to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00 at the end of any fiscal quarter. 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. Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of September 30, 2017, we were in compliance with these covenants.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2016 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

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 our ability to maintain or expand our 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 the 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 and outlook and risk profile of BHC at September 30, 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 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.

(c) On October 4, 2017, Fitch affirmed BBB+ rating and maintained a Stable outlook.

The following table represents the credit ratings of Black Hills Power at September 30, 2017:

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

There were no rating changes for Black Hills Power from previously disclosed ratings.

Capital Requirements

Capital Expenditures

Actual and forecasted capital requirements are as follows (in thousands):

	Expenditures for the Nine Months Ended September 30, 2017 [a]	Total 2017 Planned Expenditures [b]	Total 2018 Planned Expenditures	Total 2019 Planned Expenditures
Electric Utilities	$ 113,199	$ 134,000	$ 149,000	$ 193,000
Gas Utilities	122,482	187,000	263,000	279,000
Power Generation	1,899	1,000	2,000	14,000
Mining	4,315	7,000	7,000	7,000
Oil and Gas [c]	16,951	21,000	—	—
Corporate	5,075	7,000	9,000	13,000
	$ 263,921	$ 357,000	$ 430,000	$ 506,000

(a) Expenditures for the nine months ended September 30, 2017 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the nine months ended September 30, 2017.
(c) Expenditures reflect the completion of two wells previously drilled in 2015 to meet minimum daily quantity requirements for the Piceance Basin gathering and processing contract.

We have updated our planned 2018 and 2019 capital expenditures to primarily reflect the following:

- additional planned transmission and distribution investments at our Electric Utilities in 2018 and 2019; and
- additional planned growth and integrity investments in our Gas utilities, primarily as a result of gaining further knowledge of the SourceGas utilities.

We continue to evaluate potential future acquisitions and other growth opportunities when they arise. As a result, capital expenditures may vary significantly from the estimates identified above.

Contractual Obligations

There have been no significant changes in contractual obligations from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K except for those described in Note 16 of the Notes to Condensed Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 20 of the Notes to the Consolidated Financial Statements in our 2016 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2016 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q 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 inc 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 2 - 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 was 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 was 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 described in our 2016 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2016 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to natural gas price volatility. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. The fair value of our Utilities Group's derivative contracts is summarized below (in thousands) as of:

	September 30, 2017	December 31, 2016	September 30, 2016
Net derivative (liabilities) assets	$ (6,541)	$ (4,733)	$ (10,800)
Cash collateral offset in Derivatives	5,452	7,882	11,584
Cash collateral included in Other current assets	2,841	4,840	4,602
Net asset (liability) position	$ 1,752	$ 7,989	$ 5,386

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2017 and 2018 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at September 30, 2017, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2017					
Swaps - MMBtu	—	—	—	540,000	540,000
Weighted Average Price per MMBtu	$ —	$ —	$ —	$ 3.04	$ 3.04

Crude Oil

	March 31	June 30	September 30	December 31	Total Year
2017					
Swaps - Bbls	—	—	—	18,000	18,000
Weighted Average Price per Bbl	$—	$—	$ —	$ 52.33	$ 52.33
Calls - Bbls	—	—	—	9,000	9,000
Weighted Average Price per Bbl	$—	$—	$ —	$ 50.00	$ 50.00
2018					
Swaps - Bbls	9,000	9,000	9,000	9,000	36,000
Weighted Average Price per Bbl	$ 49.58	$ 49.85	$ 50.12	$ 50.45	$ 50.00

The fair value of our Oil and Gas segment's derivative contracts is summarized below (in thousands) as of:

	September 30, 2017	December 31, 2016	September 30, 2016
Net derivative (liabilities) assets	$ 110	$ (1,433)	$ 2,177
Cash collateral offset in Derivatives	544	2,733	—
Net asset (liability) position	$ 654	$ 1,300	$ 2,177

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. Historically, we have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated long-term refinancings. Further details of the swap agreements are set forth in Note 9 of the Notes to Consolidated Financial Statements in our 2016 Annual Report on Form 10-K and in Note 10 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	September 30, 2017 Designated Interest Rate Swaps	December 31, 2016 Designated Interest Rate Swap [(a)]	September 30, 2016 Designated Interest Rate Swaps [(a)]
Notional	$ —	$50,000	$75,000
Weighted average fixed interest rate	— %	4.94 %	4.97 %
Maximum terms in months	0	1	4
Derivative assets, non-current	$ —	$—	$—
Derivative liabilities, current	$ —	$90	$654
Derivative liabilities, non-current	$ —	$—	$—
Pre-tax accumulated other comprehensive income (loss)	$ —	$(90)	$(654)

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(a) The $25 million in swaps expired in October 2016 and 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.

ITEM 4. 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) as of September 30, 2017. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at September 30, 2017.

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 September 30, 2017, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2016 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2016 Annual Report on Form 10-K filed with the SEC, except those stated below:

While we plan to sell Black Hills Exploration and Production, Inc. ("BHEP"), our oil and gas exploration business, and we have initiated a sales process and retained advisors to facilitate the process, there is no assurance that we can complete the transaction or recognize any particular level of proceeds.

We plan to divest all of our oil and gas assets and fully exit our oil and gas business. Such a divestiture and exit is subject to various risks, including: suitable purchasers may not be available or willing to purchase the assets on terms and conditions reasonable to us or may only be interested in acquiring a portion of the assets; we may incur substantial costs in connection with the marketing and sale of the assets; uncertainties associated with the sale may cause a loss of key management personnel at BHEP which could make it more difficult to sell the assets or operate the business in the event that we are unable to sell it; and we may be required to record an additional impairment charge that could have an adverse effect on our financial condition and results of operations.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no unregistered securities sold during the nine months ended September 30, 2017.

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 Quarterly Report on Form 10-Q.

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 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). 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).
Exhibit 2.2*	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).
Exhibit 2.3*	Guaranty of Black Hills Corporation in favor of Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, dated as of July 12, 2015 (filed as Exhibit 2.3 to the Registrant's Form 8-K filed on July 14, 2015).
Exhibit 3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
Exhibit 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).
Exhibit 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).
Exhibit 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).

Exhibit 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).
Exhibit 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).

Exhibit 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).
Exhibit 4.6*	Indenture dated as of April 16, 2007 between SourceGas LLC and U.S. Bank National Association, as Trustee (relating to $325 million, 5.90% Senior Notes due 2017) (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 18, 2016).
Exhibit 4.7*	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).
Exhibit 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.
Exhibit 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.
Exhibit 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.
Exhibit 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.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

SIGNATURES

Pursuant to the requirements 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

/s/ David R. Emery
David R. Emery, Chairman and
Chief Executive Officer

/s/ Richard W. Kinzley
Richard W. Kinzley, Senior Vice President and
Chief Financial Officer

Dated: November 3, 2017