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 March 31, 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 April 30, 2017
Common stock, $1.00 par value	53,461,825 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)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update issued by the FASB
ATM	At-the-market equity offering program
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 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)

Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural gas-fired generating facility jointly owned by Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company. Cheyenne Prairie was placed into commercial service on October 1, 2014.
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.
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
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
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
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)
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.
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
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.
SSIR	System Safety and Integrity Rider
VIE	Variable interest entity

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(in thousands, except per share amounts)	
Revenue	$ 554,003	$ 449,959
Operating expenses:		
Fuel, purchased power and cost of natural gas sold	219,777	171,856
Operations and maintenance	122,130	107,062
Depreciation, depletion and amortization	48,647	44,407
Taxes - property, production and severance	13,969	12,117
Impairment of long-lived assets	—	14,496
Other operating expenses	1,969	26,431
Total operating expenses	406,492	376,369
Operating income	147,511	73,590
Other income (expense):		
Interest charges -		
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(35,096)	(32,074)
Allowance for funds used during construction - borrowed	486	501
Capitalized interest	169	235
Interest income	41	655
Allowance for funds used during construction - equity	492	707
Other income (expense), net	(102)	688
Total other income (expense), net	(34,010)	(29,288)
Income before income taxes	113,501	44,302
Income tax benefit (expense)	(33,355)	(4,252)
Net income	80,146	40,050
Net income attributable to noncontrolling interest	(3,623)	(48)
Net income available for common stock	$ 76,523	$ 40,002
Earnings per share of common stock:		
Earnings per share, Basic	$ 1.44	$ 0.78
Earnings per share, Diluted	$ 1.39	$ 0.77
Weighted average common shares outstanding:		
Basic	53,152	51,044
Diluted	54,932	51,858
Dividends declared per share of common stock	$ 0.445	$ 0.420

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

(unaudited)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(in thousands)	
Net income (loss)	$ 80,146	$ 40,050
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 March 31, 2017 and 2016, respectively)	(31)	(36)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(154) and $(172) for the three months ended March 31, 2017 and 2016, respectively)	260	322
Derivative instruments designated as cash flow hedges:		
Net unrealized gains (losses) on interest rate swaps (net of tax of $(32) and $5,251 for the three months ended March 31, 2017 and 2016, respectively)	58	(9,796)
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(249) and $598 for the three months ended March 31, 2017 and 2016, respectively)	463	(1,111)
Net unrealized gains (losses) on commodity derivatives (net of tax of $(342) and $(675) for the three months ended March 31, 2017 and 2016, respectively)	584	1,152
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $106 and $1,348 for the three months ended March 31, 2017 and 2016, respectively)	(181)	(2,301)
Other comprehensive income (loss), net of tax	1,153	(11,770)
Comprehensive income (loss)	81,299	28,280
Less: comprehensive income attributable to noncontrolling interest	(3,623)	(48)
Comprehensive income (loss) available for common stock	$ 77,676	$ 28,232

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		
	March 31, 2017	December 31, 2016	March 31, 2016
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 11,353	$ 13,580	$ 26,046
Restricted cash and equivalents	2,409	2,274	1,839
Accounts receivable, net	224,714	263,289	206,276
Materials, supplies and fuel	84,484	107,210	78,176
Derivative assets, current	1,541	4,138	1,486
Regulatory assets, current	53,476	49,260	54,108
Other current assets	23,425	27,063	34,287
Total current assets	401,402	466,814	402,218
Investments	12,712	12,561	12,126
Property, plant and equipment	6,436,610	6,412,223	6,063,943
Less: accumulated depreciation and depletion	(1,943,538)	(1,943,234)	(1,742,070)
Total property, plant and equipment, net	4,493,072	4,468,989	4,321,873
Other assets:			
Goodwill	1,299,454	1,299,454	1,306,169
Intangible assets, net	8,182	8,392	10,957
Regulatory assets, non-current	249,113	246,882	239,023
Derivative assets, non-current	9	222	85
Other assets, non-current	11,905	12,130	11,274
Total other assets, non-current	1,568,663	1,567,080	1,567,508
TOTAL ASSETS	$ 6,475,849	$ 6,515,444	$ 6,303,725

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		
	March 31, 2017	December 31, 2016	March 31, 2016
	(in thousands, except share amounts)		
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$ 105,074	$ 153,477	$ 100,756
Accrued liabilities	203,467	244,034	272,181
Derivative liabilities, current	464	2,459	3,965
Accrued income taxes, net	3,726	12,552	10,899
Regulatory liabilities, current	22,118	13,067	35,933
Notes payable	50,950	96,600	215,600
Current maturities of long-term debt	5,743	5,743	—
Total current liabilities	391,542	527,932	639,334
Long-term debt	3,210,730	3,211,189	3,159,055
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	577,211	535,606	500,202
Derivative liabilities, non-current	176	274	14,522
Regulatory liabilities, non-current	196,538	193,689	200,337
Benefit plan liabilities	174,827	173,682	181,270
Other deferred credits and other liabilities	135,847	138,643	124,181
Total deferred credits and other liabilities	1,084,599	1,041,894	1,020,512
Commitments and contingencies (See Notes 8, 10, 15, 16)			
Redeemable noncontrolling interest	—	4,295	4,141
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,502,252; 53,397,467; and 51,477,472 shares, respectively	53,502	53,397	51,477
Additional paid-in capital	1,143,102	1,138,982	960,605
Retained earnings	513,885	457,934	490,999
Treasury stock, at cost – 41,443; 15,258; and 30,903 shares, respectively	(2,443)	(791)	(1,573)
Accumulated other comprehensive income (loss)	(33,730)	(34,883)	(20,825)
Total stockholders' equity	1,674,316	1,614,639	1,480,683
Noncontrolling interest	114,662	115,495	—
Total equity	1,788,978	1,730,134	1,480,683
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$ 6,475,849	$ 6,515,444	$ 6,303,725

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)	Three Months Ended March 31,	
	2017	2016
Operating activities:	(in thousands)	
Net income (loss)	$ 80,146	$ 40,002
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	48,647	44,407
Deferred financing cost amortization	1,690	1,666
Impairment of long-lived assets	—	14,496
Stock compensation	3,091	4,461
Deferred income taxes	42,195	32,579
Employee benefit plans	3,242	3,466
Other adjustments, net	(2,303)	(5,000)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	22,445	25,822
Accounts receivable, unbilled revenues and other operating assets	41,052	27,559
Accounts payable and other operating liabilities	(99,482)	(73,355)
Regulatory assets - current	236	12,856
Regulatory liabilities - current	9,083	11,613
Other operating activities, net	(3,202)	(7,489)
Net cash provided by (used in) operating activities	146,840	133,083
Investing activities:		
Property, plant and equipment additions	(69,309)	(83,885)
Acquisition, net of long term debt assumed	—	(1,132,318)
Other investing activities	(185)	(329)
Net cash provided by (used in) investing activities	(69,494)	(1,216,532)
Financing activities:		
Dividends paid on common stock	(23,754)	(21,537)
Common stock issued	2,171	7,821
Net (payments) borrowings on short-term debt	(45,650)	138,800
Long-term debt - issuances	—	545,959
Long-term debt - repayments	(1,436)	—
Distributions to noncontrolling interest	(4,349)	—
Other financing activities	(6,555)	(2,409)
Net cash provided by (used in) financing activities	(79,573)	668,634
Net change in cash and cash equivalents	(2,227)	(414,815)
Cash and cash equivalents, beginning of period	13,580	440,861
Cash and cash equivalents, end of period	$ 11,353	$ 26,046

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.

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.

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 March 31, 2017, December 31, 2016, and March 31, 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 months ended March 31, 2017 and March 31, 2016, and our financial condition as of March 31, 2017, December 31, 2016, and March 31, 2016, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. March 31, 2017 reflects a full quarter of activity from the SourceGas acquisition on February 12, 2016, as compared to March 31, 2016 which reflects a partial quarter. 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. 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 $21 million as of March 31, 2016, and decreased net cash flows provided by operations by $5.3 million for the three months ended March 31, 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 March 31, 2016 and to the condensed consolidated statements of cash flows for the three months ended March 31, 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 and Adopted Accounting Standards

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. ASU 2017-07 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 period pension and post-retirement benefit costs in assets will be applied on a prospective basis. ASU 2017-07 is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. We are currently assessing the changes to the standard. The presentation changes required for net periodic pension and post-retirement costs will result in offsetting changes to Operating income and Other income and are not expected to be material.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force).* This ASU requires changes in the presentation of certain items including but not limited to debt prepayment or debt extinguishment costs; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. The ASU will be effective for fiscal years beginning after December 15, 2017. We will use the retrospective transition method to adopt this standard with fiscal years beginning after December 15, 2017. This standard will not have a material impact on our financial position, results of operations or cash flows.

Improvements to Employee Share-Based Payment Accounting, ASU 2016-09

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting*. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We implemented this ASU effective January 1, 2017, recording a cumulative-effect adjustment 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.

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 terms of more than 12 months. Lessees are permitted to make an accounting policy election to not recognize the asset and liability for leases with a term of 12 months or less. 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. In addition, the ASU expands the disclosure requirements of lease arrangements. Lessees and lessors will use a modified retrospective transition approach, which includes a number of practical expedients. The guidance is effective for the Company beginning after December 15, 2018. Early adoption is permitted. We are currently assessing the impact that adoption of ASU 2016-02 will have on our financial position, results of operations or cash flows.

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 will adopt this standard for annual and interim reporting periods beginning after December 15, 2017. We continue to actively assess all of our sources of revenue to determine the impact that adoption of the new standard will have on our financial position, results of operations and cash flows. Our evaluation includes identifying revenue streams by like contracts to allow for ease of implementation. 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 the revenue from contracts with the customer will be equivalent to the electricity or gas delivered in that period. Therefore, we do not expect that there will be a significant shift in the timing or pattern of revenue recognition for regulated tariff-based sales. The evaluation of other revenue streams is ongoing, including our non-regulated revenues and those tied to longer term contractual commitments. However, a number of industry-specific implementation issues are still unresolved and the final resolution of these issues could impact our current accounting policies and/or patterns for revenue recognition, as well as the transition method selected.

(2) ACQUISITION

2016 Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas (now referred to as Black Hills Gas Holdings). Net cash paid at acquisition was $1.1 billion, and included 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 months ended March 31, 2016 exclude approximately $16 million of after-tax transaction costs, professional fees, employee related expenses and other miscellaneous costs.

	Pro Forma Results Three Months Ended March 31, 2016 (in thousands, except per share amounts)
Revenue	$528,921
Net income (loss) available for common stock	$66,690
Earnings (loss) per share, Basic	$1.31
Earnings (loss) per share, Diluted	$1.29

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 of 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 March 31, 2017	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$ 172,170	$ 3,854	$ 22,230
Gas [(a)]	364,901	9	46,010
Power Generation [(b)]	2,102	21,465	6,530
Mining	8,355	8,191	2,890
Oil and Gas	6,475	—	(2,951)
Corporate activities [(c)] [(d)]	—	—	1,814
Inter-company eliminations	—	(33,519)	—
Total	$ 554,003	$ —	$ 76,523

Three Months Ended March 31, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$ 163,531	$ 3,745	$ 19,215
Gas [(a)]	268,667	1,806	31,927
Power Generation	1,852	21,456	8,582
Mining	7,534	8,748	2,938
Oil and Gas [(e)]	8,375	—	(7,024)
Corporate activities [(c)] [(d)]	—	—	(15,636)
Inter-company eliminations	—	(35,755)	—
Total	$ 449,959	$ —	$ 40,002

(a) Gas Utility revenue increased for the three months ended March 31, 2017 compared to the same periods 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 is net of net income attributable to noncontrolling interests of $3.5 million for the three months ended March 31, 2017.
(c) Net income (loss) available for common stock for the three months ended March 31, 2017 and March 31, 2016 included incremental, non-recurring acquisition costs, net of tax of $0.9 million and $15 million, respectively, and after-tax internal labor costs attributable to the acquisition of $0.3 million and $3.8 million, respectively.
(d) Net income (loss) available for common stock for the three months ended March 31, 2017 included a net tax benefit of approximately $3.2 million comprised of a $1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years and a tax benefit of $1.8 million driven primarily by the adjustment to the projected annual effective tax rate. Net income (loss) available for common stock for the three months ended March 31, 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 months ended March 31, 2016 includes a non-cash after-tax impairment of oil and gas properties of $8.8 million. 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:	March 31, 2017	December 31, 2016	March 31, 2016
Segment:			
Electric [(a)]	$ 2,872,989	$ 2,859,559	$ 2,703,774
Gas	3,260,989	3,307,967	3,141,897
Power Generation [(a)]	72,540	73,445	74,403
Mining	64,973	67,347	73,878
Oil and Gas [(b)]	95,212	96,435	197,291
Corporate activities	109,146	110,691	112,482
Total assets	$ 6,475,849	$ 6,515,444	$ 6,303,725

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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 $14 million for the three months ended March 31, 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:

March 31, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,679	$ 30,778	$ (639)	$ 69,818
Gas Utilities	98,027	51,926	(3,646)	146,307
Power Generation	1,353	—	—	1,353
Mining	3,197	—	—	3,197
Oil and Gas	2,952	—	(13)	2,939
Corporate	1,100	—	—	1,100
Total	$ 146,308	$ 82,704	$ (4,298)	$ 224,714

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

March 31, 2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,981	$ 32,660	$ (772)	$ 73,869
Gas Utilities	73,259	55,014	(4,363)	123,910
Power Generation	1,210	—	—	1,210
Mining	2,484	—	—	2,484
Oil and Gas	2,395	—	(13)	2,382
Corporate	2,421	—	—	2,421
Total	$ 123,750	$ 87,674	$ (5,148)	$ 206,276

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of March 31, 2017	As of December 31, 2016	As of March 31, 2016
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)] [(d)]	1	$ 23,473	$ 17,491	$ 24,479
Deferred gas cost adjustments [(a)(d)]	1	8,991	15,329	14,895
Gas price derivatives [(a)]	4	11,520	8,843	20,324
Deferred taxes on AFUDC [(b)]	45	14,976	15,227	13,677
Employee benefit plans [(c)]	12	109,172	108,556	111,661
Environmental [(a)]	subject to approval	1,089	1,108	1,162
Asset retirement obligations [(a)]	44	507	505	487
Loss on reacquired debt [(a)]	30	19,869	20,188	3,097
Renewable energy standard adjustment [(b)]	5	1,138	1,605	4,507
Deferred taxes on flow through accounting [(c)]	35	39,152	37,498	30,614
Decommissioning costs [(e)]	10	15,745	16,859	18,134
Gas supply contract termination	5	24,178	26,666	30,613
Other regulatory assets [(a)]	15	32,779	26,267	19,481
		$ 302,589	$ 296,142	$ 293,131
Regulatory liabilities				
Deferred energy and gas costs [(a)] [(d)]	1	$ 21,507	$ 10,368	$ 40,797
Employee benefit plans [(c)]	12	67,973	68,654	63,580
Cost of removal [(a)]	44	122,197	118,410	123,076
Revenue subject to refund	1	1,345	2,485	1,131
Other regulatory liabilities [(c)]	25	5,634	6,839	7,686
		$ 218,656	$ 206,756	$ 236,270

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(a) Recovery of costs, but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.
(d) 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) South Dakota Electric has approximately $12 million of decommissioning costs associated with the retirements of the Neil Simpson I and Ben French power plants for which we are allowed a rate of return, in addition to recovery of costs.

(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:

	March 31, 2017	December 31, 2016	March 31, 2016
Materials and supplies	$ 71,823	$ 68,456	$ 66,542
Fuel - Electric Utilities	3,433	3,667	5,365
Natural gas in storage held for distribution	9,228	35,087	6,269
Total materials, supplies and fuel	$ 84,484	$ 107,210	$ 78,176

(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 March 31,	
	2017	2016
Net income (loss) available for common stock	$ 76,523	$ 40,002
Weighted average shares - basic	53,152	51,044
Dilutive effect of:		
Equity Units [(a)]	1,595	720
Equity compensation	185	94
Weighted average shares - diluted	54,932	51,858

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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 March 31,	
	2017	2016
Equity compensation	—	74
Anti-dilutive shares	—	74

(8) NOTES PAYABLE

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

	March 31, 2017		December 31, 2016		March 31, 2016	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$ —	$ 28,100	$ 96,600	$ 36,000	$ 215,600	$ 24,000
CP Program	50,950	—	—	—	—	—
Total	$ 50,950	$ 28,100	$ 96,600	$ 36,000	$ 215,600	$ 24,000

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 March 31, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net amount borrowed under the CP Program during the three months ended March 31, 2017 and our notes outstanding as of March 31, 2017 were $51 million. As of March 31, 2017, the weighted average interest rate on CP Program borrowings was 1.27%.

Debt Covenants

On December 7, 2016, we amended our Revolving Credit Facility and term loan agreements, allowing the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under the amended and restated Revolving Credit Facility and term loan agreements, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs.

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	As of March 31, 2017	Covenant Requirement	
Consolidated Indebtedness to Capitalization Ratio	61%	Less than	65%

As of March 31, 2017, we were in compliance with this covenant.

(9) EQUITY

A summary of the changes in equity is as follows:

Three Months Ended March 31, 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)	76,523	3,516	80,039
Other comprehensive income (loss)	1,153	—	1,153
Dividends on common stock	(23,754)	—	(23,754)
Share-based compensation	2,392	—	2,392
Dividend reinvestment and stock purchase plan	748	—	748
Redeemable noncontrolling interest	(1,096)	—	(1,096)
Cumulative effect of ASU 2016-09 implementation	3,714	—	3,714
Other stock transactions	(3)	—	(3)
Distribution to noncontrolling interest	—	(4,349)	(4,349)
Balance at March 31, 2017	$ 1,674,316	$ 114,662	$ 1,788,978

Three Months Ended March 31, 2016	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2015	$ 1,465,867	$ —	$ 1,465,867
Net income (loss)	40,002	—	40,002
Other comprehensive income (loss)	(11,770)	—	(11,770)
Dividends on common stock	(21,543)	—	(21,543)
Share-based compensation	561	—	561
Issuance of common stock	6,824	—	6,824
Dividend reinvestment and stock purchase plan	755	—	755
Other stock transactions	(13)	—	(13)
Balance at March 31, 2016	$ 1,480,683	$ —	$ 1,480,683

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. 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 three months ended March 31, 2017. During the three months ended March 31, 2016, we issued 121,000 common shares for $7.0 million, net of $0.1 million in fees and issuance costs with settlement dates through March 31, 2016 under the ATM equity offering program.

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 required to be 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 noncontrolling interests 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:

	March 31, 2017	December 31, 2016	March 31, 2016
		(in thousands)	
Assets			
Current assets	$ 12,167	$ 12,627	$ —
Property, plant and equipment of variable interest entities, net	$ 217,083	$ 218,798	$ —
Liabilities			
Current liabilities	$ 3,464	$ 4,342	$ —

(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:

	March 31, 2017			December 31, 2016			March 31, 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	Natural Gas Futures and Swaps
Notional [(a)]	90,000	27,000	1,890,000	108,000	36,000	2,700,000	159,000	3,447,500
Maximum terms in months [(b)]	21	9	9	24	12	12	21	21

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

Based on March 31, 2017 prices, a $0.3 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

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, fixed to float swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying 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, or the Condensed Consolidated Statements of Comprehensive 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 April 2017 through May 2019. 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 least quarterly.

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:

	March 31, 2017		December 31, 2016		March 31, 2016	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	12,330,000	45	14,770,000	48	18,270,000	57
Natural gas options purchased, net	500,000	21	3,020,000	5	990,000	21
Natural gas basis swaps purchased	11,230,000	45	12,250,000	48	16,810,000	57
Natural gas over-the-counter swaps, net [(b)]	3,165,952	26	4,622,302	28	1,557,011	23
Natural gas physical contracts, net	3,015,234	12	21,504,378	10	2,135,050	12

(a) Term reflects the maximum forward period hedged.
(b) 1,180,000 MMBtus were designated as cash flow hedges for the natural gas fixed for float swaps purchased.

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, including 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. 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:

	March 31, 2017	December 31, 2016	March 31, 2016		
	Designated Interest Rate Swaps	Designated Interest Rate Swap [(a)]	Designated Interest Rate Swap [(b)]	Designated Interest Rate Swap [(b)]	Designated Interest Rate Swaps [(a)]
Notional	$ —	$ 50,000	$ 150,000	$ 250,000	$ 75,000
Weighted average fixed interest rate	—%	4.94%	2.09%	2.29%	4.97%
Maximum terms in months	0	1	13	13	10
Derivative assets, non-current	$ —	$ —	—	$ —	$ —
Derivative liabilities, current	$ —	$ 90	—	$ —	$ 2,290
Derivative liabilities, non-current	$ —	$ —	$ 3,785	$ 10,693	$ —

(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.
(b) These swaps were settled and terminated in August 2016 in conjunction with the refinancing of acquired SourceGas debt.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three months ended March 31, 2017 and 2016 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Three Months Ended March 31, 2017

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (712)	Interest expense	$ —
Commodity derivatives	Revenue	229	Revenue	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	58	Fuel, purchased power and cost of natural gas sold	—
Total		$ (425)		$ —

Three Months Ended March 31, 2016

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ 1,709	Interest expense	$ —
Commodity derivatives	Revenue	3,592	Revenue	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	57	Fuel, purchased power and cost of natural gas sold	—
Total		$ 5,358		$ —

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 months ended March 31, 2017 and 2016. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income as incurred.

	Three Months Ended March 31,	
	2017	2016
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate swaps	$ 90	$ (15,047)
Forward commodity contracts	926	1,827
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	712	(1,709)
Forward commodity contracts	(287)	(3,649)
Total other comprehensive income (loss) from hedging	$ 1,441	$ (18,578)

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 months ended March 31, 2017 and 2016 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

		Three Months Ended March 31,	
		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	$ 117	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(809)	634
		$ (692)	$ 634

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 $12 million, $8.8 million and $20 million at March 31, 2017, December 31, 2016 and March 31, 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, valued using the market approach, 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 March 31, 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 March 31, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 1,536	$ —	$ (977)	$ 559
Commodity derivatives — Utilities	—	2,642	—	(1,651)	991
Total	$ —	$ 4,178	$ —	$ (2,628)	$ 1,550
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 434	$ —	$ —	$ 434
Commodity derivatives — Utilities	—	13,139	—	(12,933)	206
Total	$ —	$ 13,573	$ —	$ (12,933)	$ 640

	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
Interest Rate Swaps	—	—	—	—	—
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 March 31, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 8,429	$ —	$ (8,429)	$ —
Commodity derivatives — Utilities	—	3,070	—	(1,499)	1,571
Total	$ —	$ 11,499	$ —	$ (9,928)	$ 1,571
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 251	$ —	$ (251)	$ —
Commodity derivatives — Utilities	—	23,428	—	(21,709)	1,719
Interest rate swaps	—	16,768	—	—	16,768
Total	$ —	$ 40,447	$ —	$ (21,960)	$ 18,487

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. Additionally, as of December 31, 2016, and March 31, 2016, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 10 as they are netted in other current assets.

The following tables present the fair value and balance sheet classification of our derivative instruments (in thousands):

As of March 31, 2017

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 722	$ —
Commodity derivatives	Derivative liabilities — current	—	305
Commodity derivatives	Derivative liabilities — non-current	—	71
Total derivatives designated as hedges		$ 722	$ 376
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 819	$ —
Commodity derivatives	Derivative assets — non-current	9	—
Commodity derivatives	Derivative liabilities — current	—	159
Commodity derivatives	Derivative liabilities — non-current	—	105
Total derivatives not designated as hedges		$ 828	$ 264

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 March 31, 2016	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 159	$ —
Commodity derivatives	Derivative assets — non-current	6	—
Commodity derivatives	Derivative liabilities — current	—	770
Commodity derivatives	Derivative liabilities — non-current	—	33
Interest rate swaps	Derivative liabilities — current	—	2,290
Interest rate swaps	Derivative liabilities — non-current	—	14,478
Total derivatives designated as hedges		$ 165	$ 17,571
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,327	$ —
Commodity derivatives	Derivative assets — non-current	79	—
Commodity derivatives	Derivative liabilities — current	—	905
Commodity derivatives	Derivative liabilities — non-current	—	11
Total derivatives not designated as hedges		$ 1,406	$ 916

(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:

	March 31, 2017		December 31, 2016		March 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$ 11,353	$ 11,353	$ 13,580	$ 13,580	$ 26,046	$ 26,046
Restricted cash and equivalents [a]	$ 2,409	$ 2,409	$ 2,274	$ 2,274	$ 1,839	$ 1,839
Notes payable [b]	$ 50,950	$ 50,950	$ 96,600	$ 96,600	$ 215,600	$ 215,600
Long-term debt, including current maturities, net of deferred financing costs [c]	$ 3,216,473	$ 3,388,809	$ 3,216,932	$ 3,351,305	$ 3,159,055	$ 3,392,652

(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.

(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 March 31, 2017	Amount Reclassified from AOCI Three months ended March 31, 2016
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (712)	$ 1,709
Commodity contracts	Revenue	229	3,592
Commodity contracts	Fuel, purchased power and cost of natural gas sold	58	57
		(425)	5,358
Income tax	Income tax benefit (expense)	143	(1,946)
Total reclassification adjustments related to cash flow hedges, net of tax		$ (282)	$ 3,412
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ 48	$ 55
Actuarial gain (loss)	Operations and maintenance	(414)	(494)
		(366)	(439)
Income tax	Income tax benefit (expense)	137	153
Total reclassification adjustments related to defined benefit plans, net of tax		$ (229)	$ (286)
Total reclassifications		$ (511)	$ 3,126

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	58	584	—	642
Amounts reclassified from AOCI	463	(181)	229	511
Ending Balance March 31, 2017	$ (17,588)	$ 170	$ (16,312)	$ (33,730)

	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	(9,796)	1,152	—	(8,644)
Amounts reclassified from AOCI	(1,111)	(2,301)	286	(3,126)
Ending Balance March 31, 2016	$ (11,248)	$ 5,917	$ (15,494)	$ (20,825)

(14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three Months Ended	March 31, 2017	March 31, 2016
	(in thousands)	
Non-cash investing and financing activities—		
Property, plant and equipment acquired with accrued liabilities	$ 28,358	$ 30,260
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$ (36,362)	$ (15,528)
Income taxes, net	$ 13	$ —

(15) EMPLOYEE BENEFIT PLANS

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

	Three Months Ended March 31,	
	2017	2016
Service cost	$ 2,005	$ 2,078
Interest cost	3,880	3,936
Expected return on plan assets	(6,129)	(5,765)
Prior service cost	14	15
Net loss (gain)	1,002	1,793
Net periodic benefit cost	$ 772	$ 2,057

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 March 31,	
	2017	2016
Service cost	$ 603	$ 467
Interest cost	533	485
Expected return on plan assets	(79)	(70)
Prior service cost (benefit)	(109)	(107)
Net loss (gain)	125	84
Net periodic benefit cost	$ 1,073	$ 859

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 March 31,	
	2017	2016
Service cost	$ 827	$ 29
Interest cost	319	314
Prior service cost	1	—
Net loss (gain)	250	207
Net periodic benefit cost	$ 1,397	$ 550

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust accounts. 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 Three Months Ended March 31, 2017	Additional Contributions Anticipated for 2017	Contributions Anticipated for 2018
Defined Benefit Pension Plans	$ —	$ 10,200	$ 10,200
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,270	$ 3,811	$ 5,115
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 396	$ 1,187	$ 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 except for those described below.

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 March 31, 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 March 31, 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.

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 March 31, 2017, the average NYMEX natural gas price was $2.73 per Mcf, adjusted to $2.48 per Mcf at the wellhead; the average NYMEX crude oil price was $47.61 per barrel, adjusted to $42.81 per barrel at the wellhead. There were no impairments for the three months ended March 31, 2017. At March 31, 2016, the average NYMEX natural gas price was $2.40 per Mcf, adjusted to $1.13 per Mcf at the wellhead; the average NYMEX crude oil price was $46.26 per barrel, adjusted to $39.80 per barrel at the wellhead. During the three months ended March 31, 2016, we recorded a pre-tax non-cash impairment of oil and gas assets included in our Oil and Gas segment of $14 million.

(18) INCOME TAXES

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

Tax (benefit) expense	Three Months Ended March 31, 2017	2016
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [a]	1.3	2.6
Percentage depletion in excess of cost [b]	(0.4)	(14.1)
Accounting for uncertain tax positions adjustment [c]	—	(11.4)
Noncontrolling interest [d]	(1.1)	—
IRC 172(f) carryback claim [e]	(1.8)	—
Tax Credits [f]	(1.2)	—
Effective tax rate adjustment [g]	(2.4)	(4.0)
Transaction costs	—	2.5
Other tax differences	—	(1.0)
	29.4 %	9.6 %

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(a) The state income tax benefit is primarily attributable to favorable flow-through adjustments.

(b) The tax benefit for the three months ended March 31, 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 three months ended March 31, 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 percent 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 three months ended March 31, 2017 are the result of Colorado Electric placing the Peak View Wind Project into service in November 2016. Peak View began generating production tax credits during the fourth quarter of 2016.

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

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:

	March 31, 2017	December 31, 2016	March 31, 2016 [b]
Accrued employee compensation, benefits and withholdings	$ 47,361	$ 56,926	$ 50,345
Accrued property taxes	41,675	40,004	40,638
Gas-gathering contract [a]	—	—	39,944
Customer deposits and prepayments	39,288	51,628	42,573
Accrued interest and contract adjustment payments	30,488	45,503	33,381
CIAC current portion	1,575	—	20,466
Other (none of which is individually significant)	43,080	49,973	44,834
Total accrued liabilities	$ 203,467	$ 244,034	$ 272,181

(a) This contract was settled on April 29, 2016.

(b) To conform with the March 31, 2017 and December 31, 2016 presentation of accrued liabilities, the accrued employee compensation, benefits and withholdings, customer deposits and prepayments, accrued interest and contract adjustment payments and other line items presented above have been reclassified within the disclosure. These changes had no effect on total accrued liabilities.

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. We are divesting non-core oil and gas assets while retaining those best suited for a cost of service gas program and we have refocused our professional staff on assisting our utilities with the implementation of a cost of service gas program.

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 months ended March 31, 2017 and 2016, and our financial condition as of March 31, 2017, December 31, 2016 and March 31, 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 64.

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 March 31, 2017 Compared to Three Months Ended March 31, 2016. Net income (loss) available for common stock for the three months ended March 31, 2017 was $77 million, or $1.39 per share, compared to Net income (loss) available for common stock of $40 million, or $0.77 per share, reported for the same period in 2016. The Net income (loss) available for common stock for the three months ended March 31, 2017 increased over the same period in the prior year primarily due to higher earnings at our Gas Utilities and Electric Utilities, lower corporate expenses, and a decrease in impairment charges on our oil and gas properties, partially offset by tax benefits realized during the same period in the prior year.

Net income (loss) available for common stock for the three months ended March 31, 2017 included a full quarter of earnings from our acquired SourceGas utilities compared to a partial quarter in the same period of the prior year, which increased earnings by approximately $12 million. Our Electric Utilities' earnings increased by approximately $3.0 million driven primarily by returns on prior year generation investments. Corporate expenses decreased by a total of $17 million after-tax compared to the same period in the prior year driven primarily by a reduction of approximately $14 million of after-tax acquisition and transition costs. The Net income (loss) available for common stock for the three months ended March 31, 2017 is net of $3.6 million of net income attributable to noncontrolling interests. We recognized a $3.2 million net tax benefit comprised primarily of tax benefits from a carryback claim and an adjustment to the annual effective tax rate during the three months ended March 31, 2017 compared to the same period in the prior year, which included approximately $11 million in tax benefits recognized from additional percentage depletion deductions claimed with respect to our oil and gas properties and the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016. The three months ended March 31, 2016 also included a non-cash after-tax ceiling test impairment on our oil and gas properties of $8.8 million.

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

	Three Months Ended March 31,		
	2017	2016	Variance
Revenue			
Revenue	$ 587,522	$ 485,714	$ 101,808
Inter-company eliminations	(33,519)	(35,755)	2,236
	$ 554,003	$ 449,959	$ 104,044
Net income (loss) available for common stock			
Electric Utilities	$ 22,230	$ 19,215	$ 3,015
Gas Utilities	46,010	31,927	14,083
Power Generation [(a)]	6,530	8,582	(2,052)
Mining	2,890	2,938	(48)
Oil and Gas [(b)] [(c)]	(2,951)	(7,024)	4,073
	74,709	55,638	19,071
Corporate activities and eliminations [(d)] [(e)]	1,814	(15,636)	17,450
Net income (loss) available for common stock	$ 76,523	$ 40,002	$ 36,521

(a) Net income (loss) available for common stock for the three months ended March 31, 2017 is net of net income attributable to noncontrolling interest of $3.5 million.
(b) Net income (loss) available for common stock for the three months ended March 31, 2016 included a non-cash after-tax impairment of our oil and gas properties of $8.8 million. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.
(c) Net income (loss) available for common stock for the three months ended March 31, 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 income (loss) available for common stock for the three months ended March 31, 2017 and March 31, 2016 included incremental, non-recurring acquisition costs, after-tax of $0.9 million and $15 million, respectively, and after-tax internal labor costs attributable to the acquisition of $0.3 million and $3.8 million, respectively.
(e) Net income (loss) available for common stock for the three months ended March 31, 2017 included a net tax benefit of approximately $3.2 million comprised primarily of tax benefits from a carryback claim for specified liability losses involving prior tax years and an adjustment to the projected annual effective tax rate. Net income (loss) available for common stock for the three months ended March 31, 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 comparable weather during the three months ended March 31, 2017 compared to the three months ended March 31, 2016. Heating degree days for the three months ended March 31, 2017 were 11% lower than normal, compared to 12% lower than normal for the same period in 2016.

- On January 17, 2017, Colorado Electric received approval from the CPUC for a settlement agreement of 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. Colorado Electric plans to issue a request for proposals for the new generation in the second quarter of 2017 and expects to present the results to the CPUC by year-end.

- Construction continued on the $54 million, 230-kV, 144 mile-long transmission line that will connect 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 is expected to be placed in service in the first half of 2017.

Gas Utilities Segment

- Gas Utilities experienced warmer than normal temperatures during the three months ended March 31, 2017 compared to the three months ended March 31, 2016. Heating degree days for the three months ended March 31, 2017 were 13% lower than normal compared to 11% lower than normal for the same period in 2016.

Oil and Gas Segment

- Oil and Gas production volumes decreased 21% for the three months ended March 31, 2017 compared to the same period in 2016. The decrease in production was due to the sale of non-core properties in 2016 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 increased by 33% for the three months ended March 31, 2017 compared to the same period in 2016. The average hedged price received for oil decreased by 4% for the three months ended March 31, 2017 compared to the same period in 2016.

Corporate Activities

- On March 29, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and changed their 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.

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 March 31,		
	2017	2016	Variance
	(in thousands)		
Revenue	$ 176,024	$ 167,276	$ 8,748
Total fuel and purchased power	68,400	66,106	2,294
Gross margin	107,624	101,170	6,454
Operations and maintenance	40,783	39,325	1,458
Depreciation and amortization	22,861	21,258	1,603
Total operating expenses	63,644	60,583	3,061
Operating income	43,980	40,587	3,393
Interest expense, net	(13,412)	(12,499)	(913)
Other income (expense), net	340	655	(315)
Income tax benefit (expense)	(8,678)	(9,528)	850
Net income	$ 22,230	$ 19,215	$ 3,015

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2017 Compared to the Three Months Ended March 31, 2016: Net income available for common stock for the Electric Utilities was $22 million for the three months ended March 31, 2017, compared to Net income available for common stock of $19 million for the three months ended March 31, 2016, as a result of:

Gross margin increased over the prior year reflecting a $2.3 million return on investment from the Peak View Wind Project, a $2.1 million increase in commercial and industrial margins driven by increased demand, and a $1.7 million increase in transmission revenues.

Operations and maintenance increased primarily due to increased property taxes with higher asset base and increased employee related costs.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of the Peak View Wind Project and the LM6000 generating plant.

Interest expense, net increased primarily due to lower interest income from affiliate borrowings as compared to prior year.

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

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

Revenue - Electric (in thousands)	Three Months Ended March 31, 2017	2016
Residential:		
South Dakota Electric	$ 20,071	$ 19,315
Wyoming Electric	10,411	10,457
Colorado Electric	23,736	23,113
Total Residential	54,218	52,885
Commercial:		
South Dakota Electric	24,291	23,589
Wyoming Electric	15,971	15,673
Colorado Electric	23,251	22,483
Total Commercial	63,513	61,745
Industrial:		
South Dakota Electric	8,454	8,501
Wyoming Electric	12,802	10,097
Colorado Electric	9,027	9,265
Total Industrial	30,283	27,863
Municipal:		
South Dakota Electric	836	831
Wyoming Electric	503	511
Colorado Electric	2,961	2,695
Total Municipal	4,300	4,037
Total Retail Revenue - Electric	152,314	146,530
Contract Wholesale:		
Total Contract Wholesale - South Dakota Electric [a]	7,843	4,174
Off-system Wholesale:		
South Dakota Electric	3,833	4,586
Wyoming Electric	1,666	1,846
Colorado Electric	11	134
Total Off-system Wholesale	5,510	6,566
Other Revenue:		
South Dakota Electric	8,466	7,646
Wyoming Electric	925	590
Colorado Electric	966	1,770
Total Other Revenue	10,357	10,006
Total Revenue - Electric	$ 176,024	$ 167,276

(a) Increase for the three months ended March 31, 2017 was primarily due to a new 50 MW power sales agreement with Cargill effective January 1, 2017.

Quantities Generated and Purchased (in MWh)	Three Months Ended March 31, 2017	2016
Generated —		
Coal-fired:		
South Dakota Electric	387,985	388,001
Wyoming Electric	184,095	179,693
Total Coal-fired	572,080	567,694
Natural Gas and Oil:		
South Dakota Electric	10,350	15,562
Wyoming Electric	6,277	7,879
Colorado Electric	11,902	2,767
Total Natural Gas and Oil	28,529	26,208
Wind:		
Colorado Electric (a)	70,543	13,061
Total Wind	70,543	13,061
Total Generated:		
South Dakota Electric	398,335	403,563
Wyoming Electric	190,372	187,572
Colorado Electric (a)	82,445	15,828
Total Generated	671,152	606,963
Purchased —		
South Dakota Electric (b)	447,497	339,690
Wyoming Electric	249,535	222,795
Colorado Electric (a)	402,427	477,883
Total Purchased	1,099,459	1,040,368
Total Generated and Purchased:		
South Dakota Electric (b)	845,832	743,253
Wyoming Electric	439,907	410,367
Colorado Electric	484,872	493,711
Total Generated and Purchased	1,770,611	1,647,331

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

Quantity Sold (in MWh)	Three Months Ended March 31, 2017	2016
Residential:		
South Dakota Electric	149,572	142,753
Wyoming Electric	67,173	68,313
Colorado Electric	145,360	149,028
Total Residential	362,105	360,094
Commercial:		
South Dakota Electric	196,406	188,888
Wyoming Electric	132,182	130,330
Colorado Electric	175,486	176,196
Total Commercial	504,074	495,414
Industrial:		
South Dakota Electric	109,796	108,021
Wyoming Electric	177,987	142,742
Colorado Electric	102,791	99,489
Total Industrial	390,574	350,252
Municipal:		
South Dakota Electric	7,605	7,441
Wyoming Electric	2,483	2,545
Colorado Electric	26,884	26,583
Total Municipal	36,972	36,569
Total Retail Quantity Sold	1,293,725	1,242,329
Contract Wholesale:		
Total Contract Wholesale - South Dakota Electric (a)	186,116	63,453
Off-system Wholesale:		
South Dakota Electric (b)	154,496	193,373
Wyoming Electric	32,353	37,493
Colorado Electric (b)	586	7,462
Total Off-system Wholesale	187,435	238,328
Total Quantity Sold:		
South Dakota Electric	803,991	703,929
Wyoming Electric	412,178	381,423
Colorado Electric	451,107	458,758
Total Quantity Sold	1,667,276	1,544,110
Other Uses, Losses or Generation, net (c):		
South Dakota Electric	41,841	39,324
Wyoming Electric	27,729	28,944
Colorado Electric	33,765	34,953
Total Other Uses, Losses and Generation, net	103,335	103,221
Total Energy	1,770,611	1,647,331

(a) Increase for the three months ended March 31, 2017 was primarily due to a new 50 MW power sales agreement with Cargill effective January 1, 2017.
(b) Decrease in 2017 generation was primarily driven by commodity prices that impacted power marketing sales.
(c) Includes company uses, line losses, and excess exchange production.

Degree Days	Three Months Ended March 31, 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	3,130	(3)%	12%	2,806	(13)%
Wyoming Electric	2,730	(10)%	(2)%	2,776	(10)%
Colorado Electric	2,119	(19)%	(7)%	2,285	(12)%
Combined [(a)]	2,587	(11)%	1%	2,561	(12)%

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

Electric Utilities Power Plant Availability	Three Months Ended March 31, 2017	2016
Coal-fired plants [(a)]	91.2%	93.9%
Other plants	97.6%	95.0%
Total availability	95.5%	94.6%

(a) Decrease is primarily due to a planned outage at Neil Simpson II during the three months ended March 31, 2017.

Gas Utilities

	Three Months Ended March 31,		
	2017	2016	Variance
	(in thousands)		
Revenue:			
Natural gas — regulated	$ 341,633	$ 254,453	$ 87,180
Other — non-regulated services	23,277	16,020	7,257
Total revenue	364,910	270,473	94,437
Cost of sales			
Natural gas — regulated	169,702	129,765	39,937
Other — non-regulated services	11,680	8,199	3,481
Total cost of sales	181,382	137,964	43,418
Gross margin	183,528	132,509	51,019
Operations and maintenance	70,759	52,687	18,072
Depreciation and amortization	20,797	15,972	4,825
Total operating expenses	91,556	68,659	22,897
Operating income (loss)	91,972	63,850	28,122
Interest expense, net	(19,782)	(13,517)	(6,265)
Other income (expense), net	177	651	(474)
Income tax benefit (expense)	(26,250)	(19,009)	(7,241)
Net income	46,117	31,975	14,142
Net (income) loss attributable to noncontrolling interest	(107)	(48)	(59)
Net income available for common stock	$ 46,010	$ 31,927	$ 14,083

Results of Operations for the Gas Utilities for the Three Months Ended March 31, 2017 Compared to the Three Months Ended March 31, 2016: Net income available for common stock for the Gas Utilities was $46 million for the three months ended March 31, 2017, compared to Net income available for common stock of $32 million for the three months ended March 31, 2016, as a result of:

Gross margin increased primarily due to margins of approximately $51 million contributed by the SourceGas utilities reflecting a full quarter of results in 2017.

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities reflecting a full quarter of results in 2017.

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.

Revenue (in thousands) [a]	Three Months Ended March 31, 2017	2016
Residential:		
Arkansas	$ 36,356	$ 15,778
Colorado	46,781	31,780
Nebraska [b]	44,502	42,546
Iowa	36,313	34,847
Kansas	26,084	22,348
Wyoming [b]	15,316	11,116
Total Residential	$ 205,352	$ 158,415
Commercial:		
Arkansas	$ 18,053	$ 7,728
Colorado	16,947	10,197
Nebraska	13,902	13,083
Iowa	15,964	15,137
Kansas	8,916	8,170
Wyoming	7,954	5,703
Total Commercial	$ 81,736	$ 60,018
Industrial:		
Arkansas	$ 2,220	$ 837
Colorado	369	254
Nebraska	150	118
Iowa	811	575
Kansas	397	630
Wyoming	999	954
Total Industrial	$ 4,946	$ 3,368
Transportation:		
Arkansas	$ 3,000	$ 1,623
Colorado	1,383	905
Nebraska [b]	18,640	11,777
Iowa	1,471	1,475
Kansas	1,942	2,043
Wyoming [b]	9,031	4,632
Total Transportation	$ 35,467	$ 22,455

Revenue (in thousands) (continued)	Three Months Ended March 31, 2017	2016
Transmission:		
Arkansas	$ 762	$ 13
Colorado	9,746	5,044
Nebraska	—	27
Wyoming	1,278	872
Total Transmission	$ 11,786	$ 5,956
Other Sales Revenue:		
Arkansas	$ 586	$ 769
Colorado	330	163
Nebraska	999	801
Iowa	109	100
Kansas	34	1,990
Wyoming	288	418
Total Other Sales Revenue	$ 2,346	$ 4,241
Total Regulated Revenue	$ 341,633	$ 254,453
Non-regulated Services	23,277	16,020
Total Revenue	$ 364,910	$ 270,473

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(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.

Gross Margin (in thousands) [(a)]	Three Months Ended March 31, 2017	2016
Residential:		
Arkansas	$ 22,444	$ 9,629
Colorado	16,832	11,477
Nebraska [(b)]	18,737	18,484
Iowa	13,791	13,607
Kansas	11,441	10,085
Wyoming [(b)]	7,806	6,300
Total Residential	$ 91,051	$ 69,582
Commercial:		
Arkansas	$ 9,571	$ 4,032
Colorado	5,151	3,155
Nebraska	4,548	4,457
Iowa	4,371	4,289
Kansas	3,011	2,911
Wyoming	3,147	2,664
Total Commercial	$ 29,799	$ 21,508

Gross Margin (in thousands) (continued)	Three Months Ended March 31, 2017	2016
Industrial:		
Arkansas	$ 850	$ 318
Colorado	113	120
Nebraska	52	45
Iowa	90	43
Kansas	207	229
Wyoming	170	203
Total Industrial	$ 1,482	$ 958
Transportation:		
Arkansas	$ 3,000	$ 1,623
Colorado	1,383	905
Nebraska (b)	18,640	11,777
Iowa	1,471	1,475
Kansas	1,942	2,043
Wyoming (b)	9,031	4,632
Total Transportation	$ 35,467	$ 22,455
Transmission:		
Arkansas	$ 762	$ 13
Colorado	9,746	5,103
Nebraska	—	27
Wyoming	1,278	812
Total Transmission	$ 11,786	$ 5,955
Other Sales Margins:		
Arkansas	$ 586	$ 769
Colorado	330	163
Nebraska	999	801
Iowa	109	100
Kansas	34	1,979
Wyoming	288	418
Total Other Sales Margins	$ 2,346	$ 4,230
Total Regulated Gross Margin	$ 171,931	$ 124,688
Non-regulated Services	11,597	7,821
Total Gross Margin	$ 183,528	$ 132,509

(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.

Gas Utilities Quantities Sold and Transportation (in Dth) [a]	Three Months Ended March 31, 2017	2016
Residential:		
Arkansas	3,563,745	1,893,080
Colorado	6,037,439	4,417,834
Nebraska [b]	5,528,468	5,484,494
Iowa	5,030,403	5,038,749
Kansas	2,928,003	2,918,074
Wyoming [b]	2,180,076	1,707,235
Total Residential	25,268,134	21,459,466
Commercial:		
Arkansas	2,173,152	1,153,574
Colorado	2,257,750	1,443,166
Nebraska	2,023,724	1,990,729
Iowa	2,600,186	2,573,951
Kansas	1,201,527	1,274,888
Wyoming	1,447,975	1,151,701
Total Commercial	11,704,314	9,588,009
Industrial:		
Arkansas	350,089	161,692
Colorado	62,187	39,348
Nebraska	23,366	18,337
Iowa	146,120	127,199
Kansas	81,849	164,345
Wyoming	263,276	272,551
Total Industrial	926,887	783,472
Total Distribution Quantities Sold	37,899,335	31,830,947
Transportation:		
Arkansas	2,479,210	1,325,428
Colorado	1,010,676	706,731
Nebraska [b]	16,697,231	12,171,095
Iowa	5,718,303	5,830,344
Kansas	4,297,939	3,813,385
Wyoming [b]	6,877,976	4,801,927
Total Transportation	37,081,335	28,648,910
Transmission:		
Arkansas	645,889	86,164
Colorado	1,619,592	91,862
Wyoming	1,466,058	463,856
Total Transmission	3,731,539	641,882
Total Quantities Sold and Transportation	78,712,209	61,121,739

(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.

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Over 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.

	Three Months Ended March 31,				
	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]	1,569	(25)%	64%	957	(16)%
Colorado	2,465	(16)%	(6)%	2,628	(9)%
Nebraska	2,647	(13)%	(1)%	2,681	(13)%
Iowa	2,932	(13)%	(5)%	3,082	(9)%
Kansas [a]	2,102	(15)%	(3)%	2,163	(13)%
Wyoming	2,984	(7)%	5%	2,849	(8)%
Combined [b]	2,718	(13)%	11%	2,449	(11)%

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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 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 three months ended March 31, 2017 compared to prior year is not a meaningful 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.

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.

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.

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

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	1/2017	1/2017	$ 1.7	$ 1.7
RMNG [(c)]	Gas - transmission and storage	11/2016	1/2017	$ 2.9	$ 2.9
Nebraska Gas Dist. [(d)]	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 January 3, 2017 Arkansas Gas filed for recovery of $1.5 million related to projects for the replacement of eligible mains (MRP) and the recovery of $0.2 million related to projects for the relocation of certain at risk meters (ARMRP). Pursuant to the Arkansas Gas Tariff, the filed rates go into effect on the date of the filing.

(c) 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.

(d) 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 March 31,		
	2017	2016	Variance
	(in thousands)		
Revenue [a]	$ 23,567	$ 23,308	$ 259
Operations and maintenance	8,054	8,042	12
Depreciation and amortization [a]	1,207	1,031	176
Total operating expense	9,261	9,073	188
Operating income	14,306	14,235	71
Interest expense, net	(587)	(814)	227
Other (expense) income, net	(18)	23	(41)
Income tax (expense) benefit	(3,655)	(4,862)	1,207
Net income	10,046	8,582	1,464
Net income attributable to noncontrolling interest	(3,516)	—	(3,516)
Net income (loss) available for common stock	$ 6,530	$ 8,582	$ (2,052)

(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 months ended March 31, 2017, was reduced by $3.5 million, attributable to this noncontrolling interest.

Results of Operations for Power Generation for the Three Months Ended March 31, 2017 Compared to the Three Months Ended March 31, 2016: Net income available for common stock for the Power Generation segment was $6.5 million for the three months ended March 31, 2017, compared to Net income available for common stock of $8.6 million for the same period in 2016 as a result of:

Revenue was comparable to the same period in the prior year, reflecting a year over year increase in PPA prices.

Operations and maintenance was comparable to the same period in the prior year.

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

Interest expense, net decreased due to higher interest income associated with the proceeds from the noncontrolling interest sale in April 2016.

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

Income tax (expense) benefit: 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 percent 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: Net income attributable to noncontrolling interest increased by $3.5 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 March 31,	
	2017	2016
Quantities Sold, Generated and Purchased (MWh) [(a)]		
Sold		
Black Hills Colorado IPP [(b)]	254,965	333,878
Black Hills Wyoming [(c)]	170,376	167,031
Total Sold	425,341	500,909
Generated		
Black Hills Colorado IPP [(b)]	254,965	333,878
Black Hills Wyoming [(c)]	140,240	138,919
Total Generated	395,205	472,797
Purchased		
Black Hills Wyoming [(c)]	21,255	28,303
Total Purchased	21,255	28,303

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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. Black Hills Colorado IPP's units back up the wind generation assets owned by Colorado Electric.
(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 March 31,	
	2017	2016
Contracted power plant fleet availability:		
Coal-fired plant	100.0%	97.8%
Natural gas-fired plants	99.1%	99.3%
Total availability	99.3%	98.9%

Mining

	Three Months Ended March 31,		
	2017	2016	Variance
	(in thousands)		
Revenue	$ 16,546	$ 16,282	$ 264
Operations and maintenance	11,094	10,434	660
Depreciation, depletion and amortization	2,165	2,479	(314)
Total operating expenses	13,259	12,913	346
Operating income (loss)	3,287	3,369	(82)
Interest (expense) income, net	(25)	(92)	67
Other income, net	541	534	7
Income tax benefit (expense)	(913)	(873)	(40)
Net income (loss)	$ 2,890	$ 2,938	$ (48)

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

	Three Months Ended March 31,	
	2017	2016
Tons of coal sold	1,049	1,002
Cubic yards of overburden moved [(a)]	2,104	1,765
Revenue per ton	$ 15.78	$ 16.25

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

Results of Operations for Mining for the Three Months Ended March 31, 2017 Compared to the Three Months Ended March 31, 2016: Net income available for common stock for the Mining segment was $2.9 million for the three months ended March 31, 2017, compared to Net income available for common stock of $2.9 million for the same period in 2016 as a result of:

Revenue was comparable to the same period in the prior year reflecting a 5% increase in tons sold, partially offset by a 3% decrease in price per ton sold. The decrease in price per ton sold was driven by contract price adjustments based on actual mining costs. 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 a production tax valuation adjustment related to the prior year.

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

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 was comparable to the same period in the prior year.

Oil and Gas

	Three Months Ended March 31,		
	2017	2016	Variance
	(in thousands)		
Revenue	$ 6,475	$ 8,375	$ (1,900)
Operations and maintenance	8,160	9,035	(875)
Depreciation, depletion and amortization	2,007	4,113	(2,106)
Impairment of long-lived assets	—	14,496	(14,496)
Total operating expenses	10,167	27,644	(17,477)
Operating income (loss)	(3,692)	(19,269)	15,577
Interest income (expense), net	(1,107)	(1,074)	(33)
Other income (expense), net	6	39	(33)
Income tax benefit (expense)	1,842	13,280	(11,438)
Net income (loss)	$ (2,951)	$ (7,024)	$ 4,073

Results of Operations for Oil and Gas for the Three Months Ended March 31, 2017 Compared to the Three Months Ended March 31, 2016: Net loss available for common stock for the Oil and Gas segment was $(3.0) million for the three months ended March 31, 2017, compared to Net loss available for common stock of $(7.0) million for the same period in 2016 as a result of:

Revenue decreased primarily due to a 21% production decrease as compared to the same period in the prior year. Natural gas production decreased primarily due to the sale of non-core properties in 2016 and limiting 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 crude oil sold decreased 4%. The lower production volumes and crude oil pricing was partially offset by a 33% 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 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 ceiling test write-down of $14 million in the first quarter of 2016 used an average NYMEX natural gas price of $2.40 per Mcf, adjusted to $1.13 per Mcf at the wellhead, and $46.26 per barrel for crude oil, adjusted to $39.80 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 first quarter of 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 March 31, 2017	Three Months Ended March 31, 2016
Production:		
Bbls of oil sold	43,202	98,067
Mcf of natural gas sold	2,051,722	2,286,606
Bbls of NGL sold	24,743	37,003
Mcf equivalent sales	2,459,392	3,097,026

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Average price received: [(a)]		
Oil/Bbl	$ 45.82	$ 47.83
Gas/Mcf	$ 1.73	$ 1.30
NGL/Bbl	$ 22.06	$ 10.36
Depletion expense/Mcfe	$ 0.45	$ 0.93

(a) Net of hedge settlement gains and losses.

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

	Three Months Ended March 31, 2017				Three Months Ended March 31, 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	$ 1.89	$ 1.27	$ 0.44	$ 3.60	$ 1.75	$ 1.09	$ 0.32	$ 3.16
Piceance	0.62	1.89	0.02	2.53	0.34	1.94	0.13	2.41
Powder River	2.97	—	0.72	3.69	2.62	—	0.56	3.18
Williston	—	—	—	—	0.95	—	0.32	1.27
All other properties	1.59	—	0.36	1.95	0.56	—	0.04	0.60
Total weighted average	$ 1.28	$ 1.42	$ 0.23	$ 2.93	$ 1.09	$ 1.15	$ 0.25	$ 2.49

(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 March 31, 2017 Compared to the Three Months Ended March 31, 2016: Net income available for common stock for Corporate was $1.8 million for the three months ended March 31, 2017, compared to Net loss available for common stock of $(16) million for the three months ended March 31, 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 include approximately $0.9 million of after-tax acquisition and transition costs, compared to $15 million of after-tax acquisition and transition costs in the same period of the prior year. Current year corporate expenses also include approximately $0.3 million of after-tax internal labor that otherwise would have been charged to other business segments compared to $3.8 million of after-tax internal labor that otherwise would have been charged to other business segments in the same period of the prior year. During the three months ended March 31, 2017, we recognized a net tax benefit of approximately $3.2 million, which included a $1.4 million tax benefit from a carryback claim for specified liability losses involving prior years and a tax benefit of $1.8 million driven primarily by the adjustment to the projected annual effective tax rate. 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 March 31, 2017, we had $3.2 million of collateral posted related to our wholesale commodity contracts transactions. At March 31, 2017, we had sufficient liquidity to cover any additional collateral that could be required to be posted under these contracts.

Cash Flow Activities

The following table summarizes our cash flows for the three months ended March 31 (in thousands):

Cash provided by (used in):		2017		2016		Increase (Decrease)
Operating activities	$	146,840	$	133,083	$	13,757
Investing activities	$	(69,494)	$	(1,216,532)	$	1,147,038
Financing activities	$	(79,573)	$	668,634	$	(748,207)

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

Operating Activities

Net cash provided by operating activities was $147 million for the three months ended March 31, 2017, compared to net cash provided by operating activities of $133 million for the same period in 2016 for a variance of $14 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $41 million higher for the three months ended March 31, 2017 compared to the same period in the prior year;

- Net cash outflows from operating assets and liabilities were $30 million for the three months ended March 31, 2017, compared to net cash outflows of $3 million in the same period in the prior year. This $27 million variance was primarily due to:

  - Cash inflows increased by approximately $13 million for the three months ended March 31, 2017 compared to the same period in the prior year primarily as a result of changes in our accounts receivable for the three months ended March 31, 2017;

  - Cash inflows decreased by approximately $15 million as a result of changes in our current regulatory assets and liabilities driven by fuel cost adjustments and commodity prices compared to the same period in the prior year; and

  - Cash outflows increased by approximately $26 million as a result of changes in accounts payable and other operating liabilities driven primarily by higher commodity prices, changes in accrued income taxes and employee liabilities for the three months ended March 31, 2017.

Investing Activities

Net cash used in investing activities was $69 million for the three months ended March 31, 2017, compared to net cash used in investing activities of $1.2 billion for the same period in 2016. The variance was primarily driven by:

- The prior year's cash outflows included $1.1 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 $69 million for the three months ended March 31, 2017 compared to $84 million for the three months ended March 31, 2016. The prior year had higher capital expenditures at our Electric Utilities primarily from generation investments at Colorado Electric.

Financing Activities

Net cash used in financing activities for the three months ended March 31, 2017 was $80 million, compared to $669 million of net cash provided by financing activities for the same period in 2016. The $748 million variance was primarily driven by:

- Long-term borrowings were higher in the prior year due to the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition;

- Net short-term borrowings decreased by $185 million. Prior year revolver borrowings were used to partially fund the SourceGas acquisition compared to current year net payments made primarily due to lower working capital requirements and lower capital expenditures;

- Proceeds from common stock decreased by approximately $5.7 million due to prior year stock issuances under our ATM equity offering program;

- Current distributions to noncontrolling interests of $4.3 million;

- Increased dividend payments of approximately $2.2 million;

- Higher current year payments on long-term debt of $1.4 million; and

- Higher other financing activities in the current year primarily driven by the $5.6 million paid for a redeemable noncontrolling interest in March 2017.

Dividends

Dividends paid on our common stock totaled $24 million for the three months ended March 31, 2017, or $0.445 per share. On April 24, 2017, our board of directors declared a quarterly dividend of $0.445 per share payable June 1, 2017, which is equivalent to an annual dividend rate of $1.78 per share. The determination of the amount of future cash dividends, if any, to be declared and paid 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 March 31, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

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

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

Credit Facility	Expiration	Current Capacity	Revolver Borrowings at March 31, 2017	CP Program Borrowings at March 31, 2017	Letters of Credit at March 31, 2017	Available Capacity at March 31, 2017
Revolving Credit Facility	August 9, 2021	$ 750	$ —	$ 51	$ 28	$ 671

The weighted average interest rate on CP Program borrowings at March 31, 2017 was 1.27%. Revolving Credit Facility and CP Program financing activity for the quarter ended March 31, 2017 was (dollars in millions):

	For the Three Months Ended March 31, 2017
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$ 111
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances)	$ 97
Average amount outstanding - commercial paper (based on daily outstanding balances) [a]	$ 76
Average amount outstanding - revolving credit facility (based on daily outstanding balances) [a]	$ 55
Weighted average interest rates - commercial paper [a]	1.16%
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 quarter 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 March 31, 2017.

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

Financing Activities

Financing activities for the three months ended March 31, 2017 consisted of short-term borrowings from our Revolving Credit Facility and CP Program. We did not issue any shares of common stock under our ATM equity offering program.

In addition to the CP Program and amended Revolving Credit Facility discussed above, other 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.

Future Financing Plans

We anticipate the following financing activities:

- Renewing our shelf registration and ATM equity offering program; and
- Remarketing junior subordinated notes maturing in 2018.

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 March 31, 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 March 31, 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 March 31, 2017:

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

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(a) On February 12, 2016, S&P reaffirmed BBB rating and maintained a Stable outlook following the closing of the SourceGas Acquisition, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.
(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 March 29, 2017, Fitch affirmed BBB+ rating and changed their 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.

The following table represents the credit ratings of Black Hills Power at March 31, 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 Three Months Ended March 31, 2017 [(a)]	Total 2017 Planned Expenditures [(b)]	Total 2018 Planned Expenditures	Total 2019 Planned Expenditures
Electric Utilities	$ 37,956	$ 121,000	$ 112,000	$ 139,000
Gas Utilities	27,072	179,000	169,000	190,000
Power Generation	1,343	2,000	9,000	18,000
Mining	66	7,000	7,000	8,000
Oil and Gas	2,608	3,000	5,000	2,000
Corporate	1,129	12,000	3,000	8,000
	$ 70,174	$ 324,000	$ 305,000	$ 365,000

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(a) Expenditures for the three months ended March 31, 2017 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the three months ended March 31, 2017.

We have removed planned Cost of Service Gas capital expenditures from this forecast due to uncertainties related to the timing of regulatory approvals and other information associated with those approvals, such as the quantity of gas to be provided from a cost of service gas program and whether such gas will be provided from producing reserve purchases or ongoing drilling programs, or both.

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 include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 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:

	March 31, 2017	December 31, 2016	March 31, 2016
Net derivative (liabilities) assets	$ (7,931)	$ (4,733)	$ (20,066)
Cash collateral offset in Derivatives	8,716	7,882	20,210
Cash collateral included in Other current assets	3,231	4,840	3,024
Net asset (liability) position	$ 4,016	$ 7,989	$ 3,168

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 March 31, 2017, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2017					
Swaps - MMBtu	—	810,000	540,000	540,000	1,890,000
Weighted Average Price per MMBtu	$ —	$ 3.06	$ 3.03	$ 3.04	$ 3.05

Crude Oil

	March 31	June 30	September 30	December 31	Total Year
2017					
Swaps - Bbls	—	18,000	18,000	18,000	54,000
Weighted Average Price per Bbl	$ —	$ 50.85	$ 51.55	$ 52.33	$ 51.58
Calls - Bbls	—	9,000	9,000	9,000	27,000
Weighted Average Price per Bbl	$ —	$ 50.00	$ 50.00	$ 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:

	March 31, 2017	December 31, 2016	March 31, 2016
Net derivative (liabilities) assets	$ 125	$ (1,433)	$ 8,178
Cash collateral offset in Derivatives	977	2,733	(8,178)
Cash Collateral included in Other current assets	—	—	1,685
Net asset (liability) position	$ 1,102	$ 1,300	$ 1,685

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:

	March 31, 2017	December 31, 2016	March 31, 2016		
	Designated Interest Rate Swaps	Designated Interest Rate Swap [(a)]	Designated Interest Rate Swap [(b)]	Designated Interest Rate Swap [(b)]	Designated Interest Rate Swaps [(a)]
Notional	$ —	$ 50,000	$ 150,000	$ 250,000	$ 75,000
Weighted average fixed interest rate	—%	4.94%	2.09%	2.29%	4.97%
Maximum terms in months	0	1	13	13	10
Derivative assets, non-current	$ —	$ —	$ —	$ —	$ —
Derivative liabilities, current	$ —	$ 90	$ —	$ —	$ 2,290
Derivative liabilities, non-current	$ —	$ —	$ 3,785	$ 10,693	$ —
Pre-tax accumulated other comprehensive income (loss)	$ —	$ (90)	$ (3,785)	$ (10,693)	$ (2,290)

(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.
(b) These swaps were settled and terminated in August 2016 in conjunction with the refinancing of acquired SourceGas debt.

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 March 31, 2017. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at March 31, 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 March 31, 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.

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.

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

There were no unregistered securities sold during the three months ended March 31, 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 file 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 file 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 file 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 10†	Form of Performance Share Award agreement effective for awards granted on or after January 1, 2017.
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.
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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.
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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: May 4, 2017

INDEX TO EXHIBITS

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Black Hills Corporation
2015 Omnibus Incentive Plan
Performance Share Award Agreement
(for Awards granted on or after January 1, 2017)

Performance Period January 1, 2017 - December 31, 2019

AWARD AGREEMENT WITH EEI INDEX AS PEER INDEX

Contents

Black Hills Corporation
2015 Omnibus Incentive Plan
Performance Share Award Agreement

Performance Period January 1, 2017 - December 31, 2019

You have been selected to be a participant in the Black Hills Corporation 2015 Omnibus Incentive Plan (the “Plan”), as specified below:

Participant: ____________

Target Performance Share Award: _______ shares

Performance Period: January 1, 2017 to December 31, 2019

Performance Measure: Total Shareholder Return (“TSR”).

Peer Index: EEI Index

The peer group for TSR performance purposes consists of all companies comprising the EEI Index. Throughout the performance period, companies may be added or dropped from the index due to mergers or other activities. At the end of the performance period, new companies that are added to the index are included in the rankings as if they had been in the ranking from the beginning, provided there is sufficient trading history to include them in the final calculation. When a company is dropped from the index, everything related to the company is excluded as if it were never in the index. Companies included in the EEI Index at the beginning of the Performance Period excluding Black Hills Corporation, are listed in Appendix A.

THIS AGREEMENT (the “Agreement”) effective January 1, 2017, represents the grant of Performance Shares by Black Hills Corporation, a South Dakota corporation (the “Company”), to the Participant named above, pursuant to the provisions of the Plan.

The Plan provides a complete description of the terms and conditions governing the Performance Shares. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan’s terms shall completely supersede and replace the conflicting terms of this Agreement.

All capitalized terms shall have the meanings ascribed to them in the Plan, unless specifically set forth otherwise herein.

The parties hereto agree as follows:

Article 1. Performance Period

The Performance Period commences on January 1, 2017 and ends on December 31, 2019.

Article 2. Value of Performance Shares

Each Performance Share shall represent and have a value equal to one share of common stock of the Company.

Article 3. Performance Shares and Achievement of Performance Measure

The number of Performance Shares to be earned under this Agreement shall be based upon the achievement of pre-established TSR performance goals as set by the Compensation Committee of the Board of Directors (the "Committee") for the Performance Period, based on the following chart:

TSR Performance Relative to Companies in Peer Index	Payout (% of Target)
90^{th} Percentile or Above	200%
50^{th} Percentile	100%
25^{th} Percentile	25%
Below 25^{th} Percentile and TSR is equal to or greater than 35%	25%
Below the 25^{th} Percentile and TSR is below 35%	0%

In addition, if TSR is negative during the Performance Period, the payout will not exceed 100% of target.

Interpolation shall be used to determine the percentile rank in the event the Company's Percentile Rank does not fall directly on one of the ranks listed in the above chart.

For this purpose, Total Shareholder Return shall be determined as follows:

$$\text{Total Shareholder Return} = \frac{\text{Change in Stock Price + Dividends Paid}}{\text{Beginning Stock Price}}$$

Beginning Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock for the twenty (20) trading days immediately prior to the first day of the Performance Period; Ending Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock for the last twenty (20) trading days of the Performance Period; Change in Stock Price shall mean the difference between the Beginning Stock Price and the Ending Stock Price; and Dividends Paid shall mean the total of all dividends paid on one (1) share of stock during the Performance Period. Following the Total Shareholder Return determination, the Company's Percentile Rank shall be determined as follows:

Percentile Rank shall be determined by listing from highest Total Shareholder Return to lowest Total Shareholder Return each company in the Peer Index (excluding the Company). The top company would have a one hundred percentile (100%) rank and the bottom company would have a zero percentile (0.0%) rank. Each company in between would be one hundred divided by n minus one (100/(n-1)) above the company below it, where "n" is the total number of companies in the Peer Index. The Company percentile rank would then be interpolated based on the Company TSR.

Article 4. Termination Provisions

Except as provided below in this Article 4 and in Article 5, a Participant shall be eligible for payment of awarded Performance Shares, as determined in Article 3, only if the Participant's employment with the Company continues through the end of the Performance Period.

If participant Retires, suffers a Disability, or dies during the Performance Period, the Participant (or the Participant's estate) shall be entitled to that proportion of the number of Performance Shares as such Participant is entitled to under Article 3 for such Performance Period that the number of full months of participation during the Performance Period bears to the total number of months in the Performance Period. The form and timing of the payment of such Performance Shares shall be as set forth in Article 8.

"Retirement" or "Retires" means a Separation from service by a Participant on or after (i) attaining the age of 55 with at least 5 years of service, or (ii) attaining the age of 65.

"Separation from service" (as defined in Treasury Regulation Section 1.409A-1(h)) during the Performance Period other than (i) due to Retirement, Disability, or death, or (ii) following a Change in Control shall require forfeiture of this entire award, with no payment to the Participant.

Article 5. Change in Control

Notwithstanding anything herein to the contrary, in the event of a Change in Control, the Participant shall be entitled to that proportion of the number of Performance Shares as such Participant is entitled to under Article 3 for such Performance Period that the number of full months of participation during the Performance Period (as of the effective date of the Change in Control) bears to the total number of months in the Performance Period. When there is a Change in Control, the TSR shall be calculated as set forth in Article 3, except that the Ending Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock for the twenty (20) trading days immediately prior to the Change in Control. Performance Shares shall be paid out to the Participant in cash within thirty (30) days of the effective date of the Change in Control.

"Change in Control" of the Company shall be deemed to have occurred (as of a particular day, as specified by the Board) upon the occurrence of any of the following events:

(a) The acquisition in a transaction or series of transactions by any Person of Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Company; provided, however, that for purposes of this Agreement, the following acquisitions will not constitute a Change in Control: (A) any acquisition by the Company; (B) any acquisition of common stock of the Company by an underwriter holding securities of the Company in connection with a public offering thereof; and (C) any acquisition by any Person pursuant to a transaction which complies with subsections (c) (i), (ii) and (iii);

(b) Individuals who, as of December 31, 2016 are members of the Board (the "Incumbent Board"), cease for any reason to constitute at least a majority of the members of the Board; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest;

(c) Consummation, following shareholder approval, of a reorganization, merger, or consolidation of the Company, or a sale or other disposition of all or substantially all of the assets of the Company (each a “Business Combination”), unless, in each case, immediately following such Business Combination, all of the following have occurred: (i) all or substantially all of the individuals and entities who were beneficial owners of shares of the common stock of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more than fifty percent (50%) of the combined voting power of the then outstanding shares of the entity resulting from the Business Combination or any direct or indirect parent corporation thereof (including, without limitation, an entity which as a result of such transaction owns the Company or all or substantially all of the Company’s assets either directly or through one (1) or more subsidiaries) (the “Successor Entity”); (ii) no Person (excluding any Successor Entity or any employee benefit plan or related trust, of the Company or such Successor Entity) owns, directly or indirectly, thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Successor Entity, except to the extent that such ownership existed prior to such Business Combination; and (iii) at least a majority of the members of the Board of Directors of the entity resulting from such Business Combination or any direct or indirect parent corporation thereof were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company, except pursuant to a Business Combination that complies with subsections (c) (i), (ii), and (iii) above.

(e) A Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding common stock as a result of the acquisition of common stock by the Company which, by reducing the number of shares of common stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of common stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional common stock which increases the percentage of the then outstanding common stock Beneficially Owned by the Subject Person, then a Change in Control shall occur.

(f) A Change in Control shall not be deemed to occur unless and until all regulatory approvals required in order to effectuate a Change in Control of the Company have been obtained and the transaction constituting the Change in Control has been consummated.

Notwithstanding the above provisions of this definition, to the extent that any payment under the Agreement due to a Change in Control is subject to Code Section 409A for deferred compensation, then the term “Change in Control” shall be construed in a manner that is consistent with Code Section 409A(a)(2)(A)(v), but only to the extent inconsistent with the above provisions as determined by the Board.

Article 6. Forfeiture and Repayment.

(a) In the event the Participant incurs a separation from service for a reason other than those described in Article 4 herein during the Performance Period this entire award will be forfeited, unless the separation from service follows a Change in Control.

(b) Without limiting the generality of Article 6(a), the Company reserves the right to cancel all Performance Shares awarded hereunder, whether or not vested, and require the Participant to repay all income or gains previously realized in respect of such Performance Shares, in the event of the occurrence of any of the following events:

(i) termination of Participant’s employment for Cause;

(ii) within one year following any termination of Participant’s employment, the Board determines that the Participant engaged in conduct before the Participant’s termination date that would have constituted the basis for a termination of employment for Cause;

(iii) at any time during the Participant’s employment or the twelve month period immediately following any termination of employment, Participant:

(x) publicly disparages the Company, any of its affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its affiliates or such individuals; or

(y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct; or

(iv) Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Board determines that the Participant’s conduct, activities or circumstances constitute events described in Article 6(b), in addition to any other remedies the Company has available to it, the Company may in its sole discretion:

(i) cancel any Performance Shares awarded hereby, whether or not issued; and/or

(ii) require the Participant to repay an amount equal to all income or gain realized in respect of all such Performance Shares. The amount of repayment shall include, without limitation, amounts received in connection with the delivery or sale of Shares of such Performance Shares or cash paid in respect of any Performance Shares.

There shall be no forfeiture or repayment under Article 6(b) following a Change-in-Control.

(d) The Board, in its discretion, shall determine whether a Participant’s conduct, activities or circumstances constitute events described in Article 6(b) and whether and to what extent the Performance Shares awarded hereby shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Article 6(c). The Board shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant’s outstanding Performance Shares pending an investigation of a bona fide dispute regarding Participant’s eligibility to receive a payment under the terms of this Agreement as determined by the Board in good faith.

(e) For purposes of applying this provision:

(i) “Cause” means any of the following:

(u) a Participant’s violation of his or her material duties to the Company or any of its affiliates, which continues after written notice from the Company or any affiliate to cure such violation;

(v) Participant’s willful failure to follow the lawful written directives of the Board in any material respect;

(w) Participant’s willful misconduct in connection with the performance of any of his or her duties, including but not limited to falsifying or attempting to falsify documents, books or records of the Company or any of its affiliates, making or delivering a false representation, statement or certification of compliance to the Company, misappropriating or attempting to misappropriate funds or other property of the Company or any of its affiliates, or securing or attempting to secure any personal profit in connection with any transaction entered into on behalf of the Company or any of its affiliates;

(x) Participant’s breach of any material provisions of this Agreement or any other non-competition, non-interference, non-disclosure, confidentiality or other similar agreement executed by Participant with the Company or any of its affiliates;

(y) conviction (or plea of *nolo contendere*) of the Participant of any felony, or a misdemeanor involving false statement, in connection with conduct involving the Company or any of its subsidiaries or affiliates; or

(z) intentional engagement in any activity which would constitute or cause a breach of duty of loyalty, or any fiduciary duty to the Company or any of its subsidiaries or affiliates.

(ii) "Code of Conduct" means any code of ethics or code of conduct now or hereafter adopted by the Company or any of its affiliates, including to the extent applicable the Company's Employee Conduct and Disclosure Policy, as amended or supplemented from time to time, and the Company's or subsidiary Risk Management Policies and Procedures, as amended, supplemented or replaced from time to time.

(f) Participant agrees that the provisions of this Article 6 are entered into in consideration of, and as a material inducement to, the agreements by the Company herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant's agreement to the provisions of this Article 6, the Company would not have entered into this Agreement.

Article 7. Dividends

During the Performance Period, all dividends and other distributions paid with respect to the shares of common stock shall accrue for the benefit of the Participant to be paid out to the Participant pursuant to Article 8.

Article 8. Form and Timing of Payment of Performance Shares

Payment of the Performance Shares, including accrued dividends, shall be made fifty percent (50%) in cash and fifty percent (50%) in shares of Company stock.

Payment of Performance Shares shall be made within sixty (60) calendar days following the close of the Performance Period, subject to the following:

(a) The Participant shall have no right with respect to any Award or a portion there of, until such award shall be paid to such Participant.

(b) If the Committee determines, in its sole discretion, that a Participant at any time has willfully engaged in any activity that the Committee determines was or is harmful to the Company, any unpaid pending Award will be forfeited by such Participant.

(c) All appropriate taxes will be withheld from the cash portion of the award.

Article 9. Nontransferability

Performance Shares may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. Further, except as otherwise provided in a Participant's Award Agreement, a Participant's rights under the Plan shall be exercisable during the Participant's lifetime only by the Participant or the Participant's legal representative. The terms hereof shall be binding on the executors, administrators, heirs and successors of the Participant.

Article 10. Administration

This Agreement and the rights of the Participant hereunder are subject to all the terms and conditions of the Plan, as the same may be amended from time to time by the Board of Directors, as well as to such rules and regulations as the Committee may adopt for administration of the Plan. It is expressly understood that the Committee is authorized to administer, construe, and make all determinations necessary or appropriate to the administration of the Plan and this Agreement, in its sole discretion, all of which shall be binding upon the Participant.

Any inconsistency between the Agreement and the Plan shall be resolved in favor of the Plan.

Article 11. Miscellaneous

(a) The selection of any employee for participation in the Plan shall not give such Participant any right to be retained in the employ of the Company. The right and power of the Company to dismiss or discharge any Participant at-will, is specifically reserved. Such Participant or any person claiming under or through the Participant shall not have any right or interest in the Plan or any Award thereunder, unless and until all terms, conditions, and provisions of the Plan that affect such Participant have been complied with as specified herein.

(b) With the approval of the Board, the Committee may terminate, amend, or modify the Plan; provided, however, that no such termination, amendment, or modification of the Plan may in any way adversely affect the Participant's rights under this Agreement without the Participant's written consent, except as required by law.

(c) Participant shall not have voting rights with respect to the Performance Shares. Participant shall obtain voting rights upon the settlement of Performance Shares and distribution into shares of common stock of the Company.

(d) The Participant may defer such Participant's receipt of the payment of cash and the delivery of shares of common stock, that would otherwise be due to such Participant by virtue of the satisfaction of the performance goals with respect to the Performance Shares, pursuant to the rules of the Black Hills Corporation Nonqualified Deferred Compensation Plan and the procedures set forth by the Compensation Committee. If the Participant elects to defer the receipt of the award, the Participant will be required to pay any necessary taxes from their own funds. They will not be allowed to have their deferred award reduced for tax withholding.

(e) This Agreement shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

(f) To the extent not preempted by federal law, this Agreement shall be governed by, and construed in accordance with, the laws of the State of South Dakota.

(g) Any awards received by Participant are subject to the provisions of the Stock Ownership Guidelines approved by the Board of Directors.

(h) Waiver and Modification. The provisions of this Agreement may not be waived or modified unless such waiver or modification is in writing and signed by the Company.

(i) Compliance with Exchange Act. If the Participant is subject to Section 16 of the Exchange Act, Performance Shares granted pursuant to the Award are intended to comply with all applicable conditions of Rule 16b-3 or its successors under the Exchange Act.

The following parties have caused this Agreement to be executed effective as of January 1, 2017.

Black Hills Corporation

By: ______________________

____
Participant

Companies Included in EEI Index
as of January 1, 2017, Excluding Black Hills Corporation

Companies included in the EEI Index at the beginning of the Performance Period excluding Black Hills Corporation, are as follows:

ALLETE, Inc.	ALE	MDU Resources Group, Inc.	MDU
Alliant Energy Corporation	LNT	MGE Energy, Inc.	MGEE
Ameren Corporation	AEE	NextEra Energy, Inc.	NEE
American Electric Power Company, Inc.	AEP	NiSource Inc.	NI
Avangrid, Inc.	AGR	NorthWestern Corporation	NWE
Avista Corporation	AVA	OGE Energy Corp.	OGE
CenterPoint Energy, Inc.	CNP	Otter Tail Corporation	OTTR
CMS Energy Corporation	CMS	PG&E Corporation	PCG
Consolidated Edison, Inc.	ED	Pinnacle West Capital Corporation	PNW
Dominion Resources, Inc.	D	PNM Resources, Inc.	PNM
DTE Energy Company	DTE	Portland General Electric Company	POR
Duke Energy Corporation	DUK	PPL Corporation	PPL
Edison International	EIX	Public Service Enterprise Group Inc.	PEG
El Paso Electric Company	EE	SCANA Corporation	SCG
Entergy Corporation	ETR	Sempra Energy	SRE
Eversource Energy	ES	The Southern Company	SO
Exelon Corporation	EXC	Unitil Corporation	UTL
FirstEnergy Corp.	FE	Vectren Corporation	VVC
Great Plains Energy Incorporated	GXP	WEC Energy Group, Inc.	WEC
Hawaiian Electric Industries, Inc.	HE	Westar Energy, Inc.	WR
IdaCorp, Inc.	IDA	Xcel Energy Inc.	XEL

Exhibit 31.1

CERTIFICATION

I, David R. Emery, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2017

/S/ DAVID R. EMERY

David R. Emery

Chairman and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard W. Kinzley, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2017

/S/ RICHARD W. KINZLEY

Richard W. Kinzley

Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

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

Date: May 4, 2017

/S/ DAVID R. EMERY

David R. Emery
Chairman and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Richard W. Kinzley, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

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

Date: May 4, 2017

/S/ RICHARD W. KINZLEY
Richard W. Kinzley
Senior Vice President and Chief Financial Officer

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included below.

Mine Safety and Health Administration Safety Data

Safety is a core value at Black Hills Corporation and at each of its subsidiary operations. We have in place a comprehensive safety program that includes extensive health and safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

Under the recently enacted Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operation, consisting of Wyodak Coal Mine, is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present the following information regarding certain mining safety and health matters for the three month period ended March 31, 2017. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

- Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;
- Total number of orders issued under section 104(b) of the Mine Act;
- Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;
- Total number of imminent danger orders issued under section 107(a) of the Mine Act; and
- Total dollar value of proposed assessments from MSHA under the Mine Act.

The table below sets forth the total number of citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments received during the three months ended March 31, 2017 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for WRDC, our only mining complex. All citations were abated within 24 hours of issue.

Mine/ MSHA Identification Number	Mine Act Section 104 S&S Citations issued during three months ended March 31, 2017	Mine Act Section 104(b) Orders (#)	Mine Act Section 104(d) Citations and Orders (#)	Mine Act Section 110(b)(2) Violations (#)	Mine Act Section 107(a) Imminent Danger Orders (#)	Total Dollar Value of Proposed MSHA Assessments	Total Number of Mining Related Fatalities (#)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#) (a)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Wyodak Coal Mine - 4800083	—	—	—	—	—	$ 173	—	No	—	—	—

(a) The types of proceedings by class: (1) contests of citations and orders - none; (2) contests of proposed penalties - none; (3) complaints for compensation - none; (4) complaints of discharge, discrimination or interference under Section 105 of the Mine Act - none; (5) applications for temporary relief - none; and (6) appeals of judges' decisions or orders to the FMSHRC - none.