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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2016

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, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x Accelerated filer o

Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

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

Class	Outstanding at October 31, 2016
Common stock, $1.00 par value	53,147,805 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
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
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) plus Consolidated Indebtedness as defined within the current Credit Agreement.
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 Interstate Gas	Colorado Interstate Natural Gas Pricing Index
Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Cooling degree day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
Cost of Service Gas Program (COSG)	Proposed Cost of Service Gas Program designed to provide long-term natural gas price stability for the Company's utility customers, along with a reasonable expectation of customer savings over the life of the program.
CPCN	Certificate of Public Convenience and Necessity
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)
El Paso San Juan	El Paso San Juan Natural Gas Pricing Index
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)
Northwest Wyoming Pool	Northwest Wyoming Natural Gas Pricing index
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Panhandle Eastern Pipeline	Panhandle Eastern Pipeline Natural Gas Pricing Index
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	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
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
VIE	Variable interest entity
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, is owned 80% by Pacificorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Revenue	$ 333,786	$ 272,105	$ 1,109,186	$ 986,346
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	80,194	71,627	336,539	350,778
Operations and maintenance	115,103	89,830	334,706	273,374
Depreciation, depletion and amortization	48,925	37,768	140,637	116,821
Taxes - property, production and severance	12,114	10,675	36,991	33,988
Impairment of long-lived assets	12,293	61,875	52,286	178,395
Other operating expenses	6,748	2,374	40,730	3,392
Total operating expenses	275,377	274,149	941,889	956,748
Operating income (loss)	58,409	(2,044)	167,297	29,598
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(37,306)	(22,378)	(103,989)	(61,833)
Allowance for funds used during construction - borrowed	860	478	2,115	843
Capitalized interest	282	280	785	1,037
Interest income	912	414	2,513	1,163
Allowance for funds used during construction - equity	1,211	430	2,900	563
Other income (expense), net	160	842	801	1,568
Total other income (expense), net	(33,881)	(19,934)	(94,875)	(56,659)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	24,528	(21,978)	72,422	(27,061)
Equity in earnings (loss) of unconsolidated subsidiaries	—	—	—	(344)
Impairment of equity investments	—	—	—	(5,170)
Income tax benefit (expense)	(6,644)	12,035	(11,205)	14,640
Net income (loss)	17,884	(9,943)	61,217	(17,935)
Net income attributable to noncontrolling interest	(3,753)	—	(6,415)	—
Net income (loss) available for common stock	$ 14,131	$ (9,943)	$ 54,802	$ (17,935)
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic	$ 0.27	$ (0.22)	$ 1.06	$ (0.40)
Earnings (loss) per share, Diluted	$ 0.26	$ (0.22)	$ 1.04	$ (0.40)
Weighted average common shares outstanding:				
Basic	52,184	44,635	51,583	44,598
Diluted	53,733	44,635	52,893	44,598
Dividends declared per share of common stock	$ 0.420	$ 0.405	$ 1.260	$ 1.215

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

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

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Net income (loss)	$ 17,884	$ (9,943)	$ 61,217	$ (17,935)
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $(260) and $(1,609) for the three months ended 2016 and 2015 and $10,605 and $(1,482) for the nine months ended 2016 and 2015, respectively)	(551)	2,773	(20,617)	2,644
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $566 and $558 for the three months ended 2016 and 2015 and $2,450 and $2,548 for the nine months ended 2016 and 2015, respectively)	(923)	(948)	(4,137)	(3,450)
Benefit plan liability adjustments - net gain (loss) (net of tax (expense) benefit of $0 and $0 for the three months ended 2016 and 2015 and $0 and $16 for the nine months ended 2016 and 2015, respectively)	—	—	—	(27)
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $19 and $19 for the three months ended 2016 and 2015 and $58 and $58 for the nine months ended 2016 and 2015, respectively)	(36)	(36)	(108)	(108)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(171) and $(247) for the three months ended 2016 and 2015 and $(516) and $(742) for the nine months ended 2016 and 2015, respectively)	323	459	966	1,374
Other comprehensive income (loss), net of tax	(1,187)	2,248	(23,896)	433
Comprehensive income (loss)	16,697	(7,695)	37,321	(17,502)
Less: comprehensive income attributable to noncontrolling interest	(3,753)	—	(6,415)	—
Comprehensive income (loss) available for common stock	$ 12,944	$ (7,695)	$ 30,906	$ (17,502)

See Note 16 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of		
	September 30, 2016	December 31, 2015	September 30, 2015
		(in thousands)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 62,964	$ 456,535	$ 38,841
Restricted cash and equivalents	2,140	1,697	2,462
Accounts receivable, net	154,617	147,486	115,502
Materials, supplies and fuel	113,475	86,943	90,349
Derivative assets, current	4,382	—	—
Income tax receivable, net	—	368	—
Deferred income tax assets, net, current	—	—	47,783
Regulatory assets, current	50,561	57,359	51,962
Other current assets	30,032	71,763	55,383
Total current assets	418,171	822,151	402,282
Investments	12,416	11,985	12,148
Property, plant and equipment	6,306,119	4,976,778	4,882,420
Less: accumulated depreciation and depletion	(1,841,116)	(1,717,684)	(1,617,723)
Total property, plant and equipment, net	4,465,003	3,259,094	3,264,697
Other assets:			
Goodwill	1,300,379	359,759	359,527
Intangible assets, net	8,944	3,380	3,440
Regulatory assets, non-current	234,240	175,125	182,337
Derivative assets, non-current	183	3,441	—
Other assets, non-current	12,800	7,382	7,501
Total other assets, non-current	1,556,546	549,087	552,805
TOTAL ASSETS	$ 6,452,136	$ 4,642,317	$ 4,231,932

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)

(unaudited)	As of		
	September 30, 2016	December 31, 2015	September 30, 2015
	(in thousands, except share amounts)		
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$ 141,780	$ 105,468	$ 91,633
Accrued liabilities	228,522	232,061	229,889
Derivative liabilities, current	1,941	2,835	3,312
Accrued income taxes, net	10,909	—	308
Regulatory liabilities, current	16,925	4,865	5,647
Notes payable	75,000	76,800	117,900
Current maturities of long-term debt	5,743	—	—
Total current liabilities	480,820	422,029	448,689
Long-term debt	3,211,768	1,853,682	1,553,167
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	533,865	450,579	494,834
Derivative liabilities, non-current	317	156	722
Regulatory liabilities, non-current	186,496	148,176	152,164
Benefit plan liabilities	171,633	146,459	158,682
Other deferred credits and other liabilities	141,007	155,369	136,462
Total deferred credits and other liabilities	1,033,318	900,739	942,864
Commitments and contingencies (See Notes 10, 11, 12, 18, 19)			
Redeemable noncontrolling interest	4,206	—	—
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,131,469; 51,231,861; and 44,891,626 shares, respectively	53,131	51,232	44,892
Additional paid-in capital	1,123,527	953,044	753,856
Retained earnings	462,090	472,534	504,864
Treasury stock, at cost – 22,368; 39,720; and 36,711 shares, respectively	(1,155)	(1,888)	(1,789)
Accumulated other comprehensive income (loss)	(32,951)	(9,055)	(14,611)
Total stockholders' equity	1,604,642	1,465,867	1,287,212
Noncontrolling interest	117,382	—	—
Total equity	1,722,024	1,465,867	1,287,212
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$ 6,452,136	$ 4,642,317	$ 4,231,932

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Nine Months Ended September 30,	
	2016	2015
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$ 54,802	$ (17,935)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	140,637	116,821
Deferred financing cost amortization	4,002	3,074
Impairment of long-lived assets	52,286	183,565
Derivative fair value adjustments	(7,308)	(8,851)
Stock compensation	9,124	2,868
Deferred income taxes	38,578	(20,808)
Employee benefit plans	11,830	15,175
Other adjustments, net	(2,076)	4,013
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(5,166)	3,618
Accounts receivable, unbilled revenues and other operating assets	78,869	75,966
Accounts payable and other operating liabilities	(102,155)	(5,255)
Regulatory assets - current	8,453	27,768
Regulatory liabilities - current	(8,181)	2,457
Contributions to defined benefit pension plans	(14,200)	(10,200)
Interest rate swap settlement	(28,820)	—
Other operating activities, net	(5,998)	(6,403)
Net cash provided by (used in) operating activities	224,677	365,873
Investing activities:		
Property, plant and equipment additions	(334,098)	(349,471)
Acquisition, net of long term debt assumed	(1,124,238)	—
Other investing activities	(860)	(7,189)
Net cash provided by (used in) investing activities	(1,459,196)	(356,660)
Financing activities:		
Dividends paid on common stock	(65,247)	(54,450)
Common stock issued	107,690	2,484
Sale of noncontrolling interest	216,370	—
Short-term borrowings - issuances	208,100	287,910
Short-term borrowings - repayments	(209,900)	(245,010)
Long-term debt - issuances	1,767,608	300,000
Long-term debt - repayments	(1,162,872)	(275,000)
Distributions to noncontrolling interest	(4,516)	—
Other financing activities	(16,285)	(7,524)
Net cash provided by (used in) financing activities	840,948	8,410
Net change in cash and cash equivalents	(393,571)	17,623
Cash and cash equivalents, beginning of period	456,535	21,218
Cash and cash equivalents, end of period	$ 62,964	$ 38,841

See Note 17 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 2015 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 2015 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. Prior to March 31, 2016, our segments were reported within two business groups, our Utilities Group, containing the Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group, containing the Power Generation, Coal Mining and Oil and Gas segments. We have continued to report our operations consistently through our reportable segments; however we will no longer separate the segments by business group. We are a customer-focused, growth-oriented, vertically-integrated utility company. All of our non-utility business segments support our electric utilities, other than the Oil and Gas segment. In our oil and gas business, we are divesting non-core 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.
The following changes have been made to our Condensed Consolidated Statements of Income (Loss) to reflect combined operations and maintenance expenses, rather than by business group as previously reported, for the three and nine months ended September 30, 2015, respectively:

	For the Three Months Ended September 30, 2015			For the Nine Months Ended September 30, 2015		
(in thousands)	As Previously Reported	Presentation Reclassification	As Currently Reported	As Previously Reported	Presentation Reclassification	As Currently Reported
Utilities - operations and maintenance	$ 67,282	$ (67,282)	$ —	$ 205,630	$ (205,630)	$ —
Non-regulated energy operations and maintenance	$ 22,548	$ (22,548)	$ —	$ 67,744	$ (67,744)	$ —
Operations and maintenance	$ —	$ 89,830	$ 89,830	$ —	$ 273,374	$ 273,374

This presentation reclassification did not impact our consolidated financial position, results of operations or cash flows.

Segment Reporting Transition of Cheyenne Light's Natural Gas Distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light have been included in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations, including Cheyenne Light's electric utility operations, are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior period has been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments. See Note 3 for Revenues, Net Income and Segment Assets reclassified from the Electric Utilities segment to the Gas Utilities segment for the three and nine months ending September 30, 2015. This segment reclassification did not impact our consolidated financial position, results of operations or cash flows.

Use of Estimates and Basis of Presentation

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2016, December 31, 2015, and September 30, 2015 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2016 and September 30, 2015, and our financial condition as of September 30, 2016, December 31, 2015, and September 30, 2015, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Significant Accounting Policies

<u>Business Combinations</u>

We record acquisitions in accordance with ASC 805, *Business Combinations*, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, *Business Combinations* requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 for additional detail on the accounting for our acquisition.

<u>Noncontrolling Interest</u>

We account for changes in our controlling interests of subsidiaries according to ASC 810, *Consolidations.* ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on Noncontrolling Interests.

<u>Share-Based Compensation</u>

We account for our share-based compensation arrangements in accordance with ASC 718, *Compensation-Stock Compensation*, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures.

Recently Issued and Adopted Accounting Standards

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 are currently assessing the impact that adoption of ASU 2016-15 will have on our consolidated financial position, results of operations and 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 will be 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 are currently assessing the impact that adoption of ASU 2016-09 will have on our consolidated financial position, results of operations and 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 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 ASC 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 and 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, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. On July 9, 2015, FASB voted to defer the effective date of ASU 2014-09 by one year. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017 and early adoption is 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. As of September 30, 2016, we were actively evaluating all of our sources of revenue to determine the impact that adoption of ASU 2014-09 will have on our financial position, results of operations and cash flows.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent), ASU 2015-07

On May 1, 2015, the FASB issued ASU 2015-07, *Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)*. The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements were effective for us beginning January 1, 2016 and will be applied retrospectively to all periods presented, in our 2016 Form 10-K. This ASU will not materially affect our financial statements and disclosures, but will change certain presentation and disclosure of the fair value of certain plan assets in our pension and other postretirement benefit plan disclosures in our 2016 Form 10-K, for all periods presented.

Simplifying the Presentation of Debt Issuance Costs, ASU 2015-03

In April 2015, the FASB issued ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. Debt issuance costs related to a recognized debt liability are presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as an asset. Amortization of these costs will continue to be reported as interest expense. ASU 2015-03 is effective for annual and interim reporting periods beginning after December 15, 2015. We adopted ASU 2015-03 in the first quarter of 2016 on a retrospective basis. As of September 30, 2016, we presented the debt issuance costs, previously reported in other assets, as direct deductions from the carrying amount of long-term debt. The implementation of this standard resulted in reductions of other assets, non-current and long-term debt of $13 million and $15 million in the Condensed Consolidated Balance Sheets as of December 31, 2015, and September 30, 2015, respectively. Adoption of ASU 2015-03 did not have a material impact on our financial position.

Simplifying the Accounting for Measurement-Period Adjustments, ASU 2015-16

In September 2015, the FASB issued ASU 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*. This ASU eliminates the requirement to retrospectively account for changes to provisional amounts recognized at the acquisition date in a business combination. ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustments are determined, including the effect of the change in the provisional amount as if the accounting had been completed at the acquisition date. The provisions of this ASU are effective for fiscal years beginning after December 31, 2015, including interim periods within those fiscal years and should be applied prospectively to adjustments to provisional amounts that occur after the effective date. We have implemented ASU 2015-16 as of January 1, 2016. Adoption of this standard did not have a material impact on our financial position, results of operations and cash flows.

(2) ACQUISITION

Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, including the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments for capital expenditures, indebtedness and working capital. Post-closing adjustments of approximately $11 million were agreed to and received from the sellers in June 2016. SourceGas is a 99.5% owned subsidiary of Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation and has been renamed Black Hills Gas Holdings, LLC. Black Hills Gas Holdings primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado.

Cash consideration of $1.135 billion paid on February 12, 2016 to close the SourceGas Acquisition included net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.325 million shares of our common stock and 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 13, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

In connection with the acquisition, the Company recorded pre-tax, incremental acquisition costs of approximately $5.2 million and $36 million, respectively, in the three and nine months ended September 30, 2016. These costs consisted of transaction costs, professional fees, employee-related expenses and other miscellaneous costs. The costs are recorded primarily in Other operating expenses on the Condensed Consolidating Income Statements. There were $4.3 million and $5.0 million of incremental acquisition costs recorded in the three and nine months ended September 30, 2015, respectively.

Our consolidated operating results for the three and nine months ended September 30, 2016 include revenues of $72 million and $217 million, respectively, and net income (loss) of $(3.8) million and $0.8 million, respectively, attributable to SourceGas for the period from February 12 through September 30, 2016. The SourceGas operating results are reported in our Gas Utilities segment. We believe the SourceGas Acquisition enhances Black Hills Corporation’s utility growth strategy, providing greater operating scale, driving more efficient delivery of services and benefiting customers.

We accounted for the SourceGas Acquisition in accordance with ASC 805, *Business Combinations*, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. Substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

We are still determining the purchase price allocation for SourceGas. A preliminary purchase price allocation of the fair value of the assets acquired and liabilities assumed is included in the table below. The cash consideration paid of $1.124 billion, net of long-term debt assumed of $760 million and a working capital adjustment received of approximately $11 million, resulted in a preliminary estimate of goodwill totaling $941 million. This estimate is subject to change and will likely result in an increase or decrease in goodwill, which could be material. We have up to one year from the acquisition date to finalize the purchase price allocation. From the time of acquisition through September 30, 2016, we decreased goodwill by $5.8 million, reflecting the working capital adjustment received of $11 million and changes in valuation estimates for long-term debt, intangible assets, accrued liabilities and deferred taxes. Approximately $251 million of the goodwill balance is amortizable for tax purposes, relating to the partnership interests that were directly acquired in the transaction. The remainder of the goodwill balance is not amortizable for tax purposes. Goodwill generated from the acquisition reflects the benefits of increased operating scale and organic growth opportunities.

	(in thousands)
Preliminary Purchase Price	$ 1,894,882
Less: Long-term debt assumed	(760,000)
Less: Working capital adjustment received	(10,644)
Consideration Paid, net of working capital adjustment received	$ 1,124,238
Preliminary Allocation of Purchase Price:	
Current Assets	$ 111,893
Property, plant & equipment, net	1,058,093
Goodwill	940,620
Deferred charges and other assets, excluding goodwill	133,215
Current liabilities	(166,807)
Long-term debt	(764,337)
Deferred credits and other liabilities	(188,439)
Total preliminary consideration paid, net of working-capital adjustment received	$ 1,124,238

Conditions of SourceGas Acquisition Regulatory Approval

The acquisition was subject to regulatory approvals from the public utility commissions in Arkansas (APSC), Colorado (CPUC), Nebraska (NPSC), and Wyoming (WPSC). Approvals were obtained from all commissions, subject to various conditions as set forth below:

The APSC order includes a 12 month base rate moratorium, an annual $0.25 million customer credit for a term of up to five-years or until we file the next rate case, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The CPUC order includes a two-year base rate moratorium for our regulated transmission and wholesale natural gas provider, a three-year base rate moratorium for our regulated gas distribution utility, an annual $0.2 million customer credit for a term of up to five-years or until we file the next rate case, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The NPSC order includes a three-year base rate moratorium, a three-year continuation of the Choice Gas program, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The WPSC order includes a three-year continuation of the Choice Gas program, as well as various other terms and reporting requirements.

All four orders also disallowed recovery of goodwill and transaction costs. Recovery of transition costs is disallowed in Arkansas, Colorado and Nebraska, however Wyoming allows for request of recovery of transition costs. Transition costs are those non-recurring costs related to the transition and integration of SourceGas. In the conditions mentioned above, the orders that include base rate moratoriums over a specified period of time do not impact our ability to adjust rates through riders or gas supply cost recovery mechanisms as allowed under the current enacted state tariffs. In certain cases, we may file for leave to increase general base rates and/or cost of sales recovery limited to material adverse changes, but only if there are changes in law or regulations or the occurrence of other extraordinary events outside of our control which result in a material adverse change in revenues, revenue requirement and/or increase in operating costs.

Settlement of Gas Supply Contract

On April 29, 2016, we settled for $40 million, a former SourceGas contract that required the company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. This contract's intangible negative fair value is included with Current liabilities of the preliminary purchase price allocation. Approximately 75% of these purchases were committed to distribution customers in Nebraska, Colorado and Wyoming, which are subject to cost recovery mechanisms, while the remaining 25% was not subject to regulatory recovery. The prices to be paid under this contract varied, ranging from $6 to $8 per MMBtu at the time of acquisition and exceeded market prices. We applied for and were granted approval to terminate this agreement from the NPSC, CPUC and WPSC, on the basis that the agreement was not beneficial to customers in the long term. We received written orders allowing recovery of the net buyout costs associated with the contract termination that were allocated to regulated subsidiaries. These costs were recorded as a regulatory asset of approximately $30 million that is being recovered over a five-year period.

Pro Forma Results

We calculated the pro forma impact of the SourceGas Acquisition and the associated debt and equity financings on our operating results for the three and nine months ended September 30, 2016 and 2015. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2015:

	Pro Forma Results			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Revenue	$ 333,786	$ 344,498	$ 1,188,148	$ 1,320,047
Net income (loss) available for common stock	$ 17,376	$ (14,189)	$ 89,973	$ (13,884)
Earnings (loss) per share, Basic	$ 0.33	$ (0.28)	$ 1.74	$ (0.27)
Earnings (loss) per share, Diluted	$ 0.32	$ (0.28)	$ 1.70	$ (0.27)

We derived the pro forma results for the SourceGas Acquisition based on historical financial information obtained from the sellers and certain management assumptions. Our pro forma adjustments relate to incremental interest expense associated with the financings to effect the transaction, and for the three and nine months ended September 30, 2015, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2015, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the acquisition, and exclude any unique one-time items resulting from the acquisition that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the three and nine months ended September 30, 2016 reflect unfavorable weather impacts resulting in lower gas usage by our customers than in the same periods of the prior year. In addition, we calculated the tax impact of these adjustments at an estimated combined federal and state income tax rate of 37%.

These pro forma results are for illustrative purposes only and do not purport to be indicative of the results that would have been obtained had the SourceGas Acquisition been completed on January 1, 2015, or that may be obtained in the future.

Seller's noncontrolling interest

One of the sellers retained 0.5% of the outstanding equity interests of SourceGas under the terms of the purchase agreement. As part of the transaction, we entered into an associated option agreement with that holder of the retained interest. The terms of this agreement provide us a call option to purchase the remaining interest beginning 366 days after the initial close of the SourceGas transaction. If we choose not to exercise this option during a ninety-day period, the seller may exercise the put option to sell us the retained interest. The value of this 0.5% equity interest is shown as Redeemable noncontrolling interest on the accompanying condensed consolidated balance sheets.

(3) BUSINESS SEGMENT INFORMATION

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

Three Months Ended September 30, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric	$ 171,754	$ 2,747	$ 24,181
Gas [f]	141,445	—	(2,939)
Power Generation [e]	1,906	21,431	5,642
Mining	9,042	7,778	3,307
Oil and Gas [a]	9,639	—	(8,828)
Corporate activities [c]	—	—	(7,232)
Inter-company eliminations	—	(31,956)	—
Total	$ 333,786	$ —	$ 14,131

Three Months Ended September 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric [d]	$ 176,042	$ 2,548	$ 22,659
Gas [d]	75,155	—	652
Power Generation	2,123	21,128	9,067
Mining	8,890	8,076	3,047
Oil and Gas [a] [b]	9,895	—	(39,769)
Corporate activities [c]	—	—	(5,599)
Inter-company eliminations	—	(31,752)	—
Total	$ 272,105	$ —	$ (9,943)

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

Nine Months Ended September 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss) Available for Common Stock
Segment:			
Electric [d]	$ 504,049	$ 8,481	$ 57,844
Gas [d]	416,950	—	27,475
Power Generation	5,782	62,452	24,761
Mining	26,084	23,541	9,106
Oil and Gas [a] [b]	33,481	—	(130,079)
Corporate activities [c]	—	—	(7,042)
Inter-company eliminations	—	(94,474)	—
Total	$ 986,346	$ —	$ (17,935)

(a) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 includes non-cash after-tax impairments of oil and gas properties of $7.9 million and $33 million and $36 million and $113 million, respectively. See Note 20 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) available for common stock for the nine months ended September 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 20 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 included incremental, non-recurring acquisition costs, net of tax of $4.0 million and $24 million; and $2.8 million and $3.0 million respectively, and after-tax internal labor costs attributable to the acquisition of $1.7 million and $7.4 million; and $1.2 million and $1.8 million respectively. See Note 2 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(d) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utility segment. Cheyenne Light's gas utility results for the three and nine months ended September 30, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Revenue of $6.2 million and $31 million, respectively, and Net loss of $1.0 million and Net income of $0.5 million, respectively, previously reported in the Electric Utility segment in 2015 are now included in the Gas Utility segment.

(e) Net income (loss) available for common stock is net of net income attributable to noncontrolling interests of $3.8 million and $6.4 million for the three and nine months ended September 30, 2016.

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

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

Total Assets (net of inter-company eliminations) as of:	September 30, 2016	December 31, 2015	September 30, 2015
Segment:			
Electric [(a)] [(b)]	$ 2,824,145	$ 2,720,004	$ 2,706,654
Gas [(b)] [(e)]	3,182,852	999,778	967,225
Power Generation [(a)]	77,570	60,864	78,666
Mining	66,804	76,357	78,000
Oil and Gas [(c)]	158,970	208,956	280,842
Corporate activities [(d)]	141,795	576,358	120,545
Total assets	$ 6,452,136	$ 4,642,317	$ 4,231,932

(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) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utility segment. Cheyenne Light's gas utility assets as of the nine months ended September 30, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Assets of $135 million and $136 million, respectively, previously reported in the Electric Utility segment in 2015 are now presented in the Gas Utility segment as of December 31, 2015 and September 30, 2015.
(c) 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 $52 million for the nine months ended September 30, 2016, $250 million for the year ended December 31, 2015, and $178 million for the nine months ended September 30, 2015. See Note 20 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.
(d) Corporate assets at December 31, 2015 included approximately $440 million of cash from the November 23, 2015 equity offerings, which was used to partially fund the SourceGas acquisition on February 12, 2016.
(e) Includes the assets acquired in the SourceGas acquisition on February 12, 2016.

(4) ACCOUNTS RECEIVABLE

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

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

December 31, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities [(a)]	$ 41,679	$ 35,874	$ (727)	$ 76,826
Gas Utilities [(a)]	30,331	32,869	(1,001)	62,199
Power Generation	1,187	—	—	1,187
Mining	2,760	—	—	2,760
Oil and Gas	3,502	—	(13)	3,489
Corporate	1,025	—	—	1,025
Total	$ 80,484	$ 68,743	$ (1,741)	$ 147,486

September 30, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities [(a)]	$ 41,655	$ 33,979	$ (811)	$ 74,823
Gas Utilities [(a)]	20,031	11,230	(527)	30,734
Power Generation	1,186	—	—	1,186
Mining	2,684	—	—	2,684
Oil and Gas	4,522	—	(13)	4,509
Corporate	1,566	—	—	1,566
Total	$ 71,644	$ 45,209	$ (1,351)	$ 115,502

(a) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utility segment. Cheyenne Light's gas utility accounts receivable has been reclassified from the Electric Utility segment to the Gas Utility segment. Accounts receivable of $6.8 million and $2.9 million as of December 31, 2015 and September 30, 2015, respectively, previously reported in the Electric Utility segment is now presented in the Gas Utility segment.

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of September 30, 2016	As of December 31, 2015	As of September 30, 2015
Regulatory assets				
Deferred energy and fuel cost adjustments - current [a] [d]	1	$ 16,525	$ 24,751	$ 25,354
Deferred gas cost adjustments [a][d]	1	12,172	15,521	9,358
Gas price derivatives [a]	7	14,405	23,583	23,681
AFUDC [b]	45	14,093	12,870	12,580
Employee benefit plans [c] [e]	12	107,578	83,986	95,779
Environmental [a]	subject to approval	1,126	1,180	1,209
Asset retirement obligations [a]	44	507	457	675
Loss on reacquired debt [a]	30	15,918	3,133	3,169
Renewable energy standard adjustment [b]	5	1,694	5,068	5,102
Flow through accounting [c]	35	33,136	29,722	28,585
Decommissioning costs [f]	10	17,271	18,310	16,353
Gas supply contract termination	5	28,164	—	—
Other regulatory assets [a]	15	22,212	13,903	12,454
		$ 284,801	$ 232,484	$ 234,299
Regulatory liabilities				
Deferred energy and gas costs [a] [d]	1	$ 15,033	$ 7,814	$ 9,899
Employee benefit plans [c] [e]	12	65,575	47,218	53,140
Cost of removal [a]	44	114,616	90,045	86,946
Other regulatory liabilities [c]	25	8,197	7,964	7,826
		$ 203,421	$ 153,041	$ 157,811

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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) Increase compared to December 31, 2015 was driven by addition of the SourceGas employee benefit plans.
(f) South Dakota Electric has approximately $12 million of decommissioning costs associated with the retirements of the Neil Simpson I and Ben French power plants that are allowed a rate of return, in addition to recovery of costs.

Loss on reacquired debt - The increase from the prior periods is the loss on the early retirement of debt assumed in the SourceGas Acquisition. These costs are being amortized to interest expense over a maximum period of 30 years.

Gas Supply Contract Termination - Black Hills Gas Holdings had agreements under the previous ownership that required the company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The majority of these purchases were committed to distribution customers in Nebraska, Colorado, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, and exceeded market prices. We recorded a liability for this contract in our purchase price allocation. We were granted approval to terminate these agreements from the NPSC, CPUC and WPSC, on the basis that these agreements are not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a five year period. We terminated the contract and settled the liability on April 29, 2016.

Cost of Removal - Cost of Removal represents the estimated cumulative net provisions for future removal costs included in depreciation expense. The increase from the prior periods is primarily due to cost of removal recorded with the SourceGas purchase price allocation.

(6) MATERIALS, SUPPLIES AND FUEL

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

	September 30, 2016	December 31, 2015	September 30, 2015
Materials and supplies	$ 67,257	$ 55,726	$ 53,838
Fuel - Electric Utilities	4,282	5,567	6,139
Natural gas in storage held for distribution	41,936	25,650	30,372
Total materials, supplies and fuel	$ 113,475	$ 86,943	$ 90,349

(7) GOODWILL & INTANGIBLE ASSETS

Following is a summary of Goodwill included in the accompanying Condensed Consolidated Balance Sheets (in thousands):

	Electric Utilities (b)	Gas Utilities (b)	Power Generation	Total
Ending balance at December 31, 2015	$ 256,850	$ 94,144	$ 8,765	$ 359,759
Acquisition of SourceGas (a)	—	940,620	—	940,620
Ending balance at September 30, 2016	$ 256,850	$ 1,034,764	$ 8,765	$ 1,300,379

(a) Represents preliminary goodwill recorded with the acquisition of SourceGas. See Note 2 for more information.
(b) Goodwill of $6.3 million is now presented in the Gas Utilities segment as a result of the inclusion of Cheyenne Light's Gas operations in the Gas Utility segment, previously reported in the Electric Utilities segment. See Note 1 for additional details.

Following is a summary of Intangible assets included in the accompanying Condensed Consolidated Balance Sheets (in thousands):

Intangible assets, net beginning balance at December 31, 2015	$ 3,380
Additions/amortization, net (a)	5,564
Intangible assets, net, ending balance at September 30, 2016	$ 8,944

(a) Intangible assets, net acquired from SourceGas are primarily non-regulated customer relationships, and are amortized over their 10-year estimated useful lives. See Note 2 for more information.

(8) ASSET RETIREMENT OBLIGATIONS

The following table presents the details of asset retirement obligations which are included on the accompanying Condensed Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2015	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired [a]	Revisions to Prior Estimates [b] [c]	September 30, 2016
Electric Utilities	$ 4,462	$ —	$ —	$ 143	$ —	$ 11	$ 4,616
Gas Utilities	136	—	—	478	22,412	6,436	29,462
Mining	18,633	—	(15)	653	—	(5,603)	13,668
Oil and Gas	21,504	—	(814)	1,047	—	57	21,794
Total	$ 44,735	$ —	$ (829)	$ 2,321	$ 22,412	$ 901	$ 69,540

(a) Represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations. Approximately $22 million was recorded with the purchase price allocation of SourceGas.
(b) The Gas Utilities Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.
(c) The Mining Revision to Prior Estimates reflects an approximately 33% reduction in equipment costs as promulgated by the State of Wyoming.

(9) EARNINGS PER SHARE

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

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Net income (loss) available for common stock	$ 14,131	$ (9,943)	$ 54,802	$ (17,935)
Weighted average shares - basic	52,184	44,635	51,583	44,598
Dilutive effect of:				
Equity Units [a]	1,414	—	1,191	—
Equity compensation	135	—	119	—
Weighted average shares - diluted [b]	53,733	44,635	52,893	44,598

(a) Calculated using the treasury stock method.
(b) Due to our net loss for the three and nine months ended September 30, 2015, potentially dilutive securities were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing dilutive net loss per share, 58,380 and 82,130 equity compensation shares were excluded from the computations for the three and nine months ended September 30, 2015, respectively.

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

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Equity compensation	2	121	4	114
Anti-dilutive shares	2	121	4	114

(10) NOTES PAYABLE

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

	September 30, 2016		December 31, 2015		September 30, 2015	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$ 75,000	$ 30,500	$ 76,800	$ 33,399	$ 117,900	$ 30,600

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options. 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 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 0.125%, 1.125%, and 1.125%, respectively, at September 30, 2016. A 0.175% commitment fee is charged on the unused amount of the Revolving Credit Facility.

Debt Financial Covenants

On February 12, 2016, in connection with the SourceGas Acquisition discussed in Note 2, our Revolving Credit Facility and Term Loan credit agreements were amended to permit the assumption of certain indebtedness of SourceGas and to increase the Recourse Leverage Ratio. We also amended and restated SourceGas's $340 million term loan due June 30, 2017. On February 12, 2016, the maximum Recourse Leverage Ratio increased to 0.75 to 1.00 until March 31, 2017, a period of four fiscal quarters following the SourceGas acquisition; it was previously 0.65 to 1.00. On August 9, 2016, in conjunction with the amendment and restatement of the Revolving Credit Facility and Term Loan, the Recourse Leverage Ratio was amended and replaced with the Consolidated Indebtedness to Capitalization Ratio. Under the amended and restated Revolving Credit Facility and Term Loan, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00 at the end of fiscal quarters ending September 30, 2016 and December 31, 2016 and not to exceed 0.65 to 1.00 at the end of any fiscal quarter thereafter.

Except as provided above, our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	As of September 30, 2016	Covenant Requirement	
Consolidated Indebtedness to Capitalization Ratio	68%	Less than	70%

As of September 30, 2016, we were in compliance with this covenant.

(11) LONG-TERM DEBT AND CURRENT MATURITIES OF LONG-TERM DEBT

Long-term debt was as follows (dollars in thousands):

	Interest Rate at September 30, 2016	September 30, 2016	December 31, 2015	September 30, 2015
Corporate				
Remarketable junior subordinated notes due November 1, 2028	3.50%	$ 299,000	$ 299,000	$ —
Senior unsecured notes due January 15, 2026	3.95%	300,000	—	—
Unamortized discount on Senior unsecured notes due 2026		(842)	—	—
Senior unsecured notes due November 30, 2023	4.25%	525,000	525,000	525,000
Unamortized discount on Senior unsecured notes due 2023		(1,685)	(1,890)	(1,959)
Senior unsecured notes due July 15, 2020	5.88%	200,000	200,000	200,000
Senior unsecured notes due January 11, 2019	2.50%	250,000	—	—
Unamortized discount on Senior unsecured notes due 2019		(205)	—	—
Senior unsecured notes due January 15, 2027	3.15%	400,000	—	—
Unamortized discount on Senior unsecured notes due 2027		(202)	—	—
Senior unsecured notes, due September 15, 2046	4.20%	300,000	—	—
Unamortized discount on Senior unsecured notes due 2046		(1,630)	—	—
Corporate term loan due August 9, 2019 [a]	1.46%	400,000	—	—
Corporate term loan due April 12, 2017 [a]		—	300,000	300,000
Corporate term loan due June 7, 2021	2.32%	25,842	—	—
Total Corporate Debt		2,695,278	1,322,110	1,023,041
Electric Utilities				
First Mortgage Bonds due October 20, 2044	4.43%	85,000	85,000	85,000
First Mortgage Bonds due October 20, 2044	4.53%	75,000	75,000	75,000
First Mortgage Bonds due August 15, 2032	7.23%	75,000	75,000	75,000
First Mortgage Bonds due November 1, 2039	6.13%	180,000	180,000	180,000
Unamortized discount on First Mortgage Bonds due 2039		(96)	(99)	(99)
First Mortgage Bonds due November 20, 2037	6.67%	110,000	110,000	110,000
Industrial development revenue bonds due September 1, 2021 [b]	0.86%	7,000	7,000	7,000
Industrial development revenue bonds due March 1, 2027 [b]	0.86%	10,000	10,000	10,000
Series 94A Debt, variable rate due June 1, 2024 [b]	1.01%	2,855	2,855	2,855
Total Electric Utilities Debt		544,759	544,756	544,756
Total long-term debt		3,240,037	1,866,866	1,567,797
Less current maturities		5,743	—	—
Less deferred financing costs [c]		22,526	13,184	14,630
Long-term debt, net of current maturities		$ 3,211,768	$ 1,853,682	$ 1,553,167

(a) Variable interest rate, based on LIBOR plus a spread.
(b) Variable interest rate.
(c) Includes deferred financing costs associated with our Revolving Credit Facility of $2.5 million, $1.7 million and $1.9 million as of September 30, 2016, December 31, 2015 and September 30, 2015, respectively.

Scheduled future maturities of debt, excluding amortization of premiums or discounts are (in thousands):

Year Ended:		
2016	$	1,436
2017	$	5,743
2018	$	5,743
2019	$	655,743
2020	$	205,742
Thereafter	$	2,370,290

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at September 30, 2016.

Current Maturities of Long-Term Debt

As of September 30, 2016, we have the following classified as Current maturities of long-term debt:

Loan	Interest Rate	Current Maturities at September 30, 2016	
Corporate			
Corporate term loan due June 7, 2021 [(a)]	2.32%		5,743
Current Maturities of Long-Term Debt		$	5,743

(a) Principal payments of $1.4 million are due quarterly.

Debt Transactions

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% ten-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046 (together the "Notes"). The proceeds of the Notes were used for the following:

- Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;
- Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;
- Repay the remaining $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;
- Pay down $100 million of the $500 million three-year unsecured term loan discussed below;
- Payment of $29 million for the settlement of $400 million notional interest rate swap; and
- Remainder was used for general corporate purposes.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan was used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017. This new term loan has substantially similar terms and covenants as the amended and restated Revolving Credit Facility.

In accordance with regulatory orders related to the early termination and settlement of the gas supply contract described in Note 5, on June 7, 2016, we entered into a 2.32%, $29 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the early termination of the gas supply contract, resulting in a regulatory asset. Principal and interest are payable quarterly at approximately $1.6 million, the first of which were paid on June 30, 2016.

On January 13, 2016, we completed a public debt offering of $550 million principal amount of senior unsecured notes. The debt offering consisted of $300 million of 3.95%, ten-year senior notes due 2026, and $250 million of 2.50%, three-year senior notes due 2019. After discounts and underwriter fees, net proceeds from the offering totaled $546 million and were used as funding for the SourceGas Acquisition. The discounts are amortized over the life of each respective note.

Assumption of Long-Term Debt

At the closing of the SourceGas Acquisition on February 12, 2016, we assumed $760 million in long-term debt, consisting of the following:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 1, 2017.
- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.
- $340 million unsecured corporate term loan due June 30, 2017. Interest under this term loan was LIBOR plus a margin of 0.875%.

As of September 30, 2016, the $760 million in long-term debt assumed in the SourceGas Acquisition was repaid.

(12) EQUITY

A summary of the changes in equity is as follows:

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

Nine Months Ended September 30, 2015	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2014	$ 1,353,884	$ —	$ 1,353,884
Net income (loss)	(17,935)	—	(17,935)
Other comprehensive income (loss)	433	—	433
Dividends on common stock	(54,450)	—	(54,450)
Share-based compensation	2,998	—	2,998
Issuance of common stock	—	—	—
Dividend reinvestment and stock purchase plan	2,298	—	2,298
Other stock transactions	(16)	—	(16)
Balance at September 30, 2015	$ 1,287,212	$ —	$ 1,287,212

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. During the three months ended September 30, 2016, we issued 819,442 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through September 30, 2016, we have sold and issued an aggregate of 1,750,091 shares of common stock under the ATM equity offering program for $106 million, net of $1.1 million in commissions. Additionally, 38,781 shares for net proceeds of $2.4 million have been sold, but were not settled and are not considered issued and outstanding as of September 30, 2016.

Sale of Noncontrolling Interest in Subsidiary

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

ASC 810 requires the accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of:

	September 30, 2016	December 31, 2015	September 30, 2015
		(in thousands)	
Assets			
Current assets	$ 14,191	$ —	$ —
Property, plant and equipment of variable interest entities, net	$ 220,818	$ —	$ —
Liabilities			
Current liabilities	$ 3,353	$ —	$ —

(13) 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 2015 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; and

- Interest rate risk associated with our variable-rate debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based 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 (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and in Note 14.

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 these instruments. 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 (Loss).

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

	September 30, 2016			December 31, 2015		September 30, 2015	
	Crude Oil Futures	Natural Gas Futures and Swaps	Call Options	Crude Oil Futures	Natural Gas Futures and Swaps	Crude Oil Futures	Natural Gas Futures and Swaps
Notional [(a)]	159,000	1,625,000	36,000	198,000	4,392,500	258,000	5,392,500
Maximum terms in months [(b)]	27	15	15	24	24	27	27

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

Based on September 30, 2016 prices, a $2.4 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 (Loss), or the Condensed Consolidated Statements of Comprehensive Income (Loss).

For hedging activities associated with our retail marketing operations, 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 Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income (Loss).

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

	September 30, 2016		December 31, 2015		September 30, 2015	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	17,740,000	51	20,580,000	60	17,180,000	63
Natural gas options purchased, net [(b)]	6,540,000	17	2,620,000	3	6,300,000	6
Natural gas basis swaps purchased	13,650,000	51	18,150,000	60	12,980,000	51
Natural gas fixed for float swaps, net [(c)]	4,749,000	20	—	0	—	0
Natural gas physical commitments, net	15,666,202	13	—	0	—	0

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(a) Term reflects the maximum forward period hedged.
(b) Volumes purchased as of September 30, 2016 is net of 2,306,000 MMBtus of collar options (call purchase and put sale) transactions.
(c) 2,640,000 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. The ineffectiveness 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:

	September 30, 2016	December 31, 2015		September 30, 2015
	Interest Rate Swaps (b)	Interest Rate Swaps (a)	Interest Rate Swaps (b)	Interest Rate Swaps (b)
Notional	$ 75,000	$ 250,000	$ 75,000	$ 75,000
Weighted average fixed interest rate	4.97%	2.29%	4.97%	4.97%
Maximum terms in years	0.33	1.33	1.00	1.33
Derivative assets, non-current	$ —	$ 3,441	$ —	$ —
Derivative liabilities, current	$ 654	$ —	$ 2,835	$ 3,312
Derivative liabilities, non-current	$ —	$ —	$ 156	$ 722

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(a) These swaps were settled in August 2016 in conjunction with the refinancing of acquired SourceGas debt.
(b) These swaps are designated to borrowings on our Revolving Credit Facility and are priced using three-month LIBOR, matching the floating portion of the related borrowings.

Based on September 30, 2016 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.4 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. This total includes the amortization of the $28 million loss currently deferred in AOCI. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

Three Months Ended September 30, 2016

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (465)	Interest expense	$ 840	Interest expense	$ —
Commodity derivatives	727	Revenue	(2,201)	Revenue	—
Commodity derivatives	(553)	Fuel, purchased power and cost of natural gas sold	(128)	Fuel, purchased power and cost of natural gas sold	—
Total	$ (291)		$ (1,489)		$ —

Three Months Ended September 30, 2015

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (898)	Interest expense	$ 1,603	Interest expense	$ —
Commodity derivatives	5,280	Revenue	(3,109)	Revenue	—
Total	$ 4,382		$ (1,506)		$ —

Nine Months Ended September 30, 2016

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (31,130)	Interest expense	$ 2,530	Interest expense	$ —
Commodity derivatives	(312)	Revenue	(9,140)	Revenue	—
Commodity derivatives	220	Fuel, purchased power and cost of natural gas sold	23	Fuel, purchased power and cost of natural gas sold	—
Total	$ (31,222)		$ (6,587)		$ —

Nine Months Ended September 30, 2015

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	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	$ (2,674)	Interest expense	$ 4,709	Interest expense	$ —
Commodity derivatives	6,800	Revenue	(10,707)	Revenue	—
Total	$ 4,126		$ (5,998)		$ —

(14) 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 2015 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 (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:

- The interest rate swaps are valued using the market approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting a Level 2 disclosure by using the credit default spread of the obligor, if available, or a generic credit default spread curve that takes into account our credit ratings, and the credit rating of our counterparty.

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

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

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

As of December 31, 2015	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
			(in thousands)		
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 10,644	$ —	$ (10,644)	$ —
Commodity derivatives —Utilities	—	2,293	—	(2,293)	—
Interest Rate Swaps	—	3,441	—	—	3,441
Total	$ —	$ 16,378	$ —	$ (12,937)	$ 3,441
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 556	$ —	$ (556)	$ —
Commodity derivatives — Utilities	—	24,585	—	(24,585)	—
Interest rate swaps	—	2,991	—	—	2,991
Total	$ —	$ 28,132	$ —	$ (25,141)	$ 2,991

As of September 30, 2015	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
			(in thousands)		
Assets:					
Commodity derivatives — Oil and Gas	$ —	$ 11,264	$ —	$ (11,264)	$ —
Commodity derivatives — Utilities	—	3,123	—	(3,123)	—
Interest Rate Swaps	—	—	—	—	—
Total	$ —	$ 14,387	$ —	$ (14,387)	$ —
Liabilities:					
Commodity derivatives — Oil and Gas	$ —	$ 467	$ —	$ (467)	$ —
Commodity derivatives — Utilities	—	24,445	—	(24,445)	—
Interest rate swaps	—	4,034	—	—	4,034
Total	$ —	$ 28,946	$ —	$ (24,912)	$ 4,034

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, 2015, and September 30, 2015, 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 13 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 September 30, 2016

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

As of December 31, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 9,981	$ —
Commodity derivatives	Derivative assets — non-current	663	—
Interest rate swaps	Derivative assets — non-current	3,441	—
Commodity derivatives	Derivative liabilities — current	—	465
Commodity derivatives	Derivative liabilities — non-current	—	91
Interest rate swaps	Derivative liabilities — current	—	2,835
Interest rate swaps	Derivative liabilities — non-current	—	156
Total derivatives designated as hedges		$ 14,085	$ 3,547
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ —	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	9,586
Commodity derivatives	Derivative liabilities — non-current	—	12,706
Total derivatives not designated as hedges		$ —	$ 22,292

As of September 30, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 9,181	$ —
Commodity derivatives	Derivative assets — non-current	2,083	—
Commodity derivatives	Derivative liabilities — current	—	375
Commodity derivatives	Derivative liabilities — non-current	—	92
Interest rate swaps	Derivative liabilities — current	—	3,312
Interest rate swaps	Derivative liabilities — non-current	—	722
Total derivatives designated as hedges		$ 11,264	$ 4,501
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ —	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	8,427
Commodity derivatives	Derivative liabilities — non-current	—	12,895
Total derivatives not designated as hedges		$ —	$ 21,322

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 14, were as follows (in thousands) as of:

	September 30, 2016		December 31, 2015		September 30, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$ 62,964	$ 62,964	$ 456,535	$ 456,535	$ 38,841	$ 38,841
Restricted cash and equivalents [a]	$ 2,140	$ 2,140	$ 1,697	$ 1,697	$ 2,462	$ 2,462
Notes payable [a]	$ 75,000	$ 75,000	$ 76,800	$ 76,800	$ 117,900	$ 117,900
Long-term debt, including current maturities, net of deferred financing costs [b]	$ 3,217,511	$ 3,525,362	$ 1,853,682	$ 1,992,274	$ 1,553,167	$ 1,718,964

(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) 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.

(16) OTHER COMPREHENSIVE INCOME (LOSS)

The components of the reclassification adjustments, net of tax, included in Other Comprehensive Income (Loss) for the periods were as follows (in thousands):

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI			
		Three Months Ended		Nine Months Ended	
		September 30, 2016	September 30, 2015	September 30, 2016	September 30, 2015
Gains and losses on cash flow hedges:					
Interest rate swaps	Interest expense	$ 840	$ 1,603	$ 2,530	$ 4,709
Commodity contracts	Revenue	(2,201)	(3,109)	(9,140)	(10,707)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(128)	—	23	—
		(1,489)	(1,506)	(6,587)	(5,998)
Income tax	Income tax benefit (expense)	566	558	2,450	2,548
Reclassification adjustments related to cash flow hedges, net of tax		$ (923)	$ (948)	$ (4,137)	$ (3,450)
Amortization of defined benefit plans:					
Prior service cost	Operations and maintenance	$ (55)	$ (55)	$ (165)	$ (166)
Actuarial gain (loss)	Operations and maintenance	494	706	1,482	2,116
		439	651	1,317	1,950
Income tax	Income tax benefit (expense)	(152)	(228)	(459)	(684)
Reclassification adjustments related to defined benefit plans, net of tax		$ 287	$ 423	$ 858	$ 1,266

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets are as follows (in thousands):

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
Balance as of December 31, 2014	$ (3,912)	$ 9,005	$ (20,137)	$ (15,044)
Other comprehensive income (loss), net of tax	332	263	395	990
Balance as of March 31, 2015	(3,580)	9,268	(19,742)	(14,054)
Other comprehensive income (loss), net of tax	503	(3,730)	422	(2,805)
Balance as of June 30, 2015	(3,077)	5,538	(19,320)	(16,859)
Other comprehensive income (loss), net of tax	457	1,368	423	2,248
Ending Balance September 30, 2015	$ (2,620)	$ 6,906	$ (18,897)	$ (14,611)
Balance as of December 31, 2015	$ 294	$ 6,431	$ (15,780)	$ (9,055)
Other comprehensive income (loss), net of tax	(11,171)	(885)	286	(11,770)
Balance as of March 31, 2016	(10,877)	5,546	(15,494)	(20,825)
Other comprehensive income (loss), net of tax	(7,649)	(3,575)	285	(10,939)
Balance as of June 30, 2016	(18,526)	1,971	(15,209)	(31,764)
Other comprehensive income (loss), net of tax	244	(1,718)	287	(1,187)
Ending Balance September 30, 2016	$ (18,282)	$ 253	$ (14,922)	$ (32,951)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine months ended	September 30, 2016	September 30, 2015
	(in thousands)	
Non-cash investing and financing activities—		
Property, plant and equipment acquired with accrued liabilities	$ 44,140	$ 52,314
Increase (decrease) in capitalized assets associated with asset retirement obligations	$ (2,285)	$ —
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$ (82,639)	$ (49,797)
Income taxes, net	$ (1,168)	$ (1,202)

(18) EMPLOYEE BENEFIT PLANS

On February 12, 2016, as disclosed in Note 2, we completed the acquisition of SourceGas, adding an additional defined benefit pension plan, two additional non-pension defined benefit postretirement plans and a 401K retirement savings plan to cover employees of the utilities acquired. Benefits under these plans are determined based on each employee's compensation, years of service, and/or age at retirement, among other factors.

In accordance with ASC 715, the SourceGas benefit liabilities were re-measured as of February 11, 2016. In addition, prior service costs not previously expensed were reclassified to a Regulatory asset and will be amortized over the average remaining service life of the plans.

Amounts recognized in the Condensed Consolidated Balance Sheets upon the February 12, 2016 acquisition are (in thousands):

	Defined Benefit Pension Plan	Non-Pension Defined Benefit Postretirement Plans
Unfunded postretirement benefit obligation	$ 22,187	$ 11,751

Defined Benefit Pension Plans

We have three defined benefit pension plans for certain eligible employees consisting of the Black Hills Corporation pension plan, Black Hills Utility Holdings' pension plan and the SourceGas retirement plan. The benefits for the pension plans are based on years of service and calculations of average earnings during a specific time period prior to retirement. All Pension Plans have been closed to new employees and frozen for certain employees who did not meet age and service based criteria.

Beginning in 2016, we changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method uses the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Previously, those costs were determined using a single weighted-average discount rate. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income, regulatory assets or regulatory liabilities. The new method provides a more precise measure of interest and service costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. We accounted for this change as a change in estimate prospectively beginning in the first quarter of 2016. The discount rates used to measure the 2016 service costs are 4.749%, 4.880% and 4.372% for pension, supplemental non-qualified defined benefit and other postretirement benefit costs, respectively. The discount rates used to measure the 2016 interest costs are 3.827%, 3.817% and 3.284% for pension, supplemental non-qualified defined benefit and other postretirement benefit costs, respectively. The previous method would have used a discount rate for both service and interest costs of 4.575% for pension, 4.500% for supplemental non-qualified defined benefit and 4.165% for other postretirement benefit costs. The decrease in the total 2016 service and interest costs is approximately $2.8 million, $0.3 million and $0.4 million for the pension, supplemental non-qualified defined benefit and other postretirement benefit costs, respectively, as compared to the previous method.

In connection with the acquisition related re-measurement of the SourceGas benefit plans we adopted the spot yield curve method, referenced above. The discount rates used to measure the 2016 interest costs are 3.690% for pension and 3.319% for other post retirement costs, effective February 11, 2016.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Service cost	$ 2,078	$ 1,494	$ 6,234	$ 4,482
Interest cost	3,936	3,880	11,808	11,640
Expected return on plan assets	(5,766)	(4,867)	(17,297)	(14,601)
Prior service cost	15	15	45	45
Net loss (gain)	1,793	2,759	5,379	8,277
Net periodic benefit cost	$ 2,056	$ 3,281	$ 6,169	$ 9,843

Defined Benefit Postretirement Healthcare Plans

With the addition of the two SourceGas Postretirement Healthcare Plans, BHC now sponsors five retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans is pre-funded via Voluntary Employees' Beneficiary Association, "VEBAs". Effective January 1, 2014, health care coverage for Medicare-eligible retirees is provided through an individual market healthcare exchange for BHC and Black Hills Utility Holdings retirees. SourceGas retirees do not participate in the individual market healthcare exchange; therefore, all permissible health claims are paid under the self-insured plan.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Service cost	$ 467	$ 464	$ 1,401	$ 1,392
Interest cost	485	450	1,455	1,350
Expected return on plan assets	(70)	(33)	(210)	(99)
Prior service cost (benefit)	(107)	(107)	(321)	(321)
Net loss (gain)	84	102	252	306
Net periodic benefit cost	$ 859	$ 876	$ 2,577	$ 2,628

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Service cost	$ 623	$ (84)	$ 1,530	$ 799
Interest cost	314	364	943	1,092
Prior service cost	1	1	2	3
Net loss (gain)	207	270	621	810
Net periodic benefit cost	$ 1,145	$ 551	$ 3,096	$ 2,704

Contributions

We anticipate that we will make contributions to the benefit plans in 2016 and 2017. Contributions to the Defined Benefit Pension Plans 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 and anticipated contributions are as follows (in thousands):

	Contributions Made Three Months Ended September 30, 2016	Contributions Made Nine Months Ended September 30, 2016	Additional Contributions Anticipated for 2016	Contributions Anticipated for 2017
Defined Benefit Pension Plans	$ 4,000	$ 14,200	$ —	$ 10,200
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,192	$ 3,576	$ 1,192	$ 4,744
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 392	$ 1,176	$ 392	$ 1,627

(19) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2015 Annual Report on Form 10-K except for those described below and in Notes 2 and 22.

Gas Supply Agreements

Acquired Utilities

In connection with the SourceGas Acquisition (see Note 2), we assumed various commitments relating to natural gas supply and transportation commitments and lease commitments, as summarized below (in thousands):

	2016	2017	2018	2019	2020	Thereafter	Total
Future minimum payments							
Pipeline capacity obligations	$ 9,718	$ 31,088	$ 34,676	$ 30,878	$ 30,878	$ 149,554	$ 286,792
Facilities and equipment	758	2,236	2,230	1,698	1,382	3,337	11,641
Total	$ 10,476	$ 33,324	$ 36,906	$ 32,576	$ 32,260	$ 152,891	$ 298,433

Also due to the acquisition, there are other commitments to purchase natural gas to meet customer needs, which are short-term or long-term in nature. At September 30, 2016, the long-term commitments to purchase physical quantities of natural gas under contracts indexed to the following indices were as follows:

	MMBtu (in thousands)					
	2016	2017	2018	2019	2020	Total
Natural Gas Indices						
Colorado Interstate Gas	1,355	6,684	—	—	—	8,039
Panhandle Eastern Pipeline	239	—	—	—	—	239
Northwest Wyoming Pool	488	1,208	1,208	720	—	3,624
El Paso San Juan	98	270	—	—	—	368

Purchases under these contracts totaled $6.2 million for the nine months ended September 30, 2016, of which $1.6 million is recovered under the applicable states' purchased-gas recovery mechanisms.

Build Transfer Agreement

On November 2, 2015, Colorado Electric executed a build-transfer agreement with Invenergy Wind Development Colorado, LLC to purchase the 60 MW, $109 million Peak View Wind Project. Peak View will be built by Invenergy Wind Development Colorado, LLC approximately 30 miles south of Pueblo, Colorado, in Huerfano and Las Animas counties. The estimated cost of $109 million includes taxes, transmission infrastructure and interconnection costs. Construction started in February of 2016 and is expected to be completed in late 2016. Under the build transfer agreement, Colorado Electric makes progress payments to Invenergy, which started in late 2015, and continue through completion of the project. Ownership of Peak View will transfer to Colorado Electric prior to commercial operation and will be operated as a utility-owned asset. BHC has guaranteed the full and complete payment and performance on behalf of Colorado Electric. At September 30, 2016, the balance of BHC's guarantee was approximately $24 million. The balance of the guarantee decreases as progress payments are made. The guarantee terminates at the earlier of 1) when BHC or Colorado Electric has paid and performed all guaranteed obligations, or 2) the second anniversary of the closing date.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of September 30, 2016, 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. The following restrictions on distributions from our subsidiaries existed at September 30, 2016:

- Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions and financing agreements. As of September 30, 2016, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(20) 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. As a result of continued low commodity prices in 2016 and throughout 2015, we recorded the following non-cash ceiling test impairments of our oil and gas assets included in our Oil and Gas segment for the three and nine months ended September 30, 2016 and September 30, 2015.

- During the three and nine months ended September 30, 2016, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $12 million and $38 million, respectively. At September 30, 2016, the average NYMEX natural gas price was $2.28 per Mcf, adjusted to $1.03 per Mcf at the wellhead; the average NYMEX crude oil price was $41.68 per barrel, adjusted to $35.88 per barrel at the wellhead.

- During the three and nine months ended September 30, 2015, we recorded pre-tax non-cash impairments of oil and gas assets included in our Oil and Gas segment of $62 million and $178 million, respectively. At September 30, 2015, the average NYMEX natural gas price was $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead; the average NYMEX crude oil price was $59.21 per barrel, adjusted to $52.82 per barrel at the wellhead.

During the second quarter of 2016, we advanced our Oil and Gas strategy, identifying certain non-core assets which may be sold as they are not expected to be utilized in the Cost of Service Gas Program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the impairments noted above.

Equity Investments in Unconsolidated Subsidiaries

At June 30, 2015, our Oil and Gas segment owned a 25% interest in a pipeline and gathering system, accounted for under the equity method of accounting. Due to sustained low commodity prices, recurring operating losses and future expectations, we reviewed this investment interest for impairment utilizing the other-than-temporary impairment model under ASC 820, Fair Value Measurements. We valued this investment applying a market method approach utilizing assumptions consistent with similar known and measurable transactions. The carrying amount of this equity method investment exceeded the fair value, and we concluded the decline is considered to be other than temporary. As a result we recorded a pre-tax impairment loss at June 30, 2015 of $5.2 million, the difference between the carrying amount and the fair value of the investment. In December of 2015, we sold our 25% interest in this pipeline and gathering system.

(21) INCOME TAXES

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

	Three Months Ended September 30,	
Tax (benefit) expense [c]	2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect) [a]	(4.0)	4.7
Percentage depletion in excess of cost	(2.3)	2.0
Accounting for uncertain tax positions adjustment	(2.4)	(1.2)
Noncontrolling interest [b]	(3.7)	—
Flow-through adjustments	(2.2)	2.4
Inter-period adjustment	7.2	11.2
AFUDC equity	(0.6)	—
Other tax differences	0.1	0.7
	27.1 %	54.8 %

(a) The state income tax benefit is primarily attributable to favorable flow-through adjustments.
(b) The reconciling item reflects limited liability company (LLC) income not subject to tax. Black Hills Colorado IPP went from a single member LLC wholly-owned by Black Hills Electric Generation to a partnership as a result of the sale of 49.9% of its membership interests in April 2016.
(c) The tax rate for the three months ended September 30, 2015 represents a tax benefit due to the net loss for the period.

The lower pre-tax income for the third quarter of 2016 is causing some of the percentages to not be reflective of the expected impact on full year operating results.

	Nine Months Ended September 30,	
Tax (benefit) expense [e]	2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect)	1.7	6.7
Percentage depletion in excess of cost [c]	(9.7)	4.5
Inter-period adjustment	0.1	—
Accounting for uncertain tax positions adjustment [d]	(7.7)	(4.7)
Noncontrolling interest	(2.5)	—
Transaction costs	1.4	—
Flow-through adjustments	(1.9)	4.7
Other tax differences	(0.9)	(1.3)
	15.5 %	44.9 %

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(c) The tax benefit 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.

(d) The tax benefit 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.

(e) The tax rate for the nine months ended September 30, 2015 represents a tax benefit due to the net loss for the period.

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.

(22) ACCRUED LIABILITIES

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

	September 30, 2016	December 31, 2015	September 30, 2015
Accrued employee compensation, benefits and withholdings	$ 57,203	$ 43,342	$ 43,390
Accrued property taxes	37,156	32,393	30,669
Accrued payments related to litigation expenses and settlements	—	38,750	33,375
Customer deposits and prepayments	51,137	53,496	33,225
Accrued interest and contract adjustment payments	42,612	25,762	22,839
CIAC current portion	5,465	14,745	16,604
Other (none of which is individually significant)	34,949	23,573	49,787
Total accrued liabilities	$ 228,522	$ 232,061	$ 229,889

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

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

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 207,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska subsidiaries. Our Gas Utilities distribute and transport natural gas through our network to approximately 1,021,000 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, our gas marketing affiliate, and through our Service Guard and Tech Services product lines. Black Hills Energy Services provides approximately 59,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas program. Service Guard primarily provides appliance repair services to approximately 64,000 residential customers 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.

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. Prior to March 31, 2016, our segments were reported within two business groups, our Utilities Group, containing the Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group, containing the Power Generation, Coal Mining and Oil and Gas segments. We have continued to report our operations consistently through our reportable segments; however, we will no longer separate the segments by business group. We are a customer-focused, growth-oriented, vertically-integrated utility company. All of our non-utility business segments support our utilities, with the exception of our Oil and Gas segment.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for our electric utilities is June through August while the normal peak usage season for our gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2016 and 2015, and our financial condition as of September 30, 2016, December 31, 2015 and September 30, 2015, 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.

SourceGas Acquisition

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. The purchase price was subject to post-closing adjustments of which $11 million was agreed to and received in June 2016.

SourceGas primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. SourceGas has been renamed Black Hills Gas Holdings, LLC and is a 99.5% owned subsidiary of Black Hills Utility Holdings. See Note 2 in Item 1 of Part I of this Quarterly Report on Form 10-Q for more information regarding the acquisition.

Segment reporting transition of Cheyenne Light's Natural Gas distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light are reported in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations including Cheyenne Light's electric utility operations are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior period has been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments. The reclassifications moving Cheyenne Light's natural gas results from the Electric Utilities segment to the Gas Utilities segment consisted of increasing Gas Utilities and decreasing (increasing) Electric Utilities Revenue, Gross Margin and Net Income (loss) by $6.2 million, $4.1 million and $(0.7) million, respectively, for the three months ended September 30, 2015, and $31 million, $15 million and $0.8 million, respectively, for the nine months ended September 30, 2015.

Utility Rebranding

All of our utilities are now operating with the trade name Black Hills Energy. We have expanded our regulated operations with the acquisition of SourceGas, as well as with our 2015 utility acquisitions. We have rebranded our Cheyenne Light utilities, Black Hills Power utility and our SourceGas utilities to operate under the name Black Hills Energy, conforming to the name under which our other utilities operate. Within our Electric utilities segment and our Gas Utilities segment, references made to our utilities are presented as follows according to their respective state:

Electric Utilities Segment

- Black Hills Energy South Dakota Electric - includes all Black Hills Power utility operations in South Dakota, Wyoming and Montana.
- Black Hills Energy Wyoming Electric - includes all Cheyenne Light electric utility operations.
- Black Hills Energy Colorado Electric - includes all Colorado Electric utility operations.

Gas Utilities Segment

- Black Hills Energy Arkansas Gas - includes the results from the acquired SourceGas utility Black Hills Energy Arkansas 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 operations and RMNG 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 operations.
- 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 Wyoming Gas - includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming operations.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 84.

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

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Net income (loss) available for common stock for the three months ended September 30, 2016 was $14 million, or $0.26 per share, compared to Net income (loss) available for common stock of $(9.9) million, or $(0.22) per share, reported for the same period in 2015. The Net income (loss) available for common stock for the three months ended September 30, 2016 increased over the same period in the prior year primarily due to higher earnings at our Electric Utilities, and a decrease in impairment charges on our oil and gas properties. Net income (loss) available for common stock for the three months ended September 30, 2016 included a non-cash after-tax impairment of oil and gas properties of $7.9 million compared to a non-cash after-tax impairment of $36 million in the same period of the prior year. The Net income (loss) available for common stock for the three months ended September 30, 2016 is net of $3.8 million of net income attributable to noncontrolling interests and includes a loss of $3.8 million from our acquired SourceGas utilities and after-tax SourceGas acquisition and transition related costs of $4.0 million. The Net income (loss) available for common stock for the three months ended September 30, 2015 included after-tax SourceGas acquisition and transition related costs of $2.8 million.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Net income (loss) available for common stock for the nine months ended September 30, 2016 was $55 million, or $1.04 per share, compared to Net income (loss) available for common stock of $(18) million, or $(0.40) per share, reported for the same period in 2015. The Net income (loss) available for common stock for the nine months ended September 30, 2016, net of $6.4 million of net income attributable to noncontrolling interests, increased over the same period in the prior year due primarily to lower impairment charges of our Oil and Gas properties; higher earnings at our Electric and Gas Utilities, which include earnings of $0.8 million from our acquired SourceGas utilities since the acquisition date of February 12, 2016; approximately $11 million in tax benefits recognized in the first quarter of 2016 from additional percentage depletion deductions that are being 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 nine months ended September 30, 2016 also included non-cash after-tax impairments of our oil and gas properties of $33 million and after-tax SourceGas acquisition and transition costs of $24 million. The Net income (loss) available for common stock for the nine months ended September 30, 2015 included a non-cash after-tax ceiling test impairment of our oil and gas properties of $113 million, after-tax SourceGas acquisition and transition costs of $3.0 million, and a non-cash after-tax impairment loss on an equity investment of $3.4 million.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
Revenue						
Revenue	$ 365,742	$ 303,856	$ 61,886	$ 1,205,305	$ 1,080,819	$ 124,486
Inter-company eliminations	(31,956)	(31,751)	(205)	(96,119)	(94,473)	(1,646)
	$ 333,786	$ 272,105	$ 61,681	$ 1,109,186	$ 986,346	$ 122,840
Net income (loss) available for common stock						
Electric Utilities	$ 24,181	$ 22,659	$ 1,522	$ 62,625	$ 57,844	$ 4,781
Gas Utilities	(2,939)	652	(3,591)	29,975	27,475	2,500
Power Generation	5,642	9,067	(3,425)	19,907	24,761	(4,854)
Mining	3,307	3,047	260	6,969	9,106	(2,137)
Oil and Gas [(a) (b) (c)]	(8,828)	(39,769)	30,941	(35,277)	(130,079)	94,802
	21,363	(4,344)	25,707	84,199	(10,893)	95,092
Corporate activities and eliminations [(d) (e)]	(7,232)	(5,599)	(1,633)	(29,397)	(7,042)	(22,355)
Net income (loss) available for common stock	$ 14,131	$ (9,943)	$ 24,074	$ 54,802	$ (17,935)	$ 72,737

(a) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 included non-cash after-tax impairments of our oil and gas properties of $7.9 million and $33 million and $36 million and $113 million, respectively. See Note 20 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) available for common stock for the nine months ended September 30, 2016 included a tax benefit of approximately $5.8 million recognized from additional percentage depletion deductions that are being claimed with respect to our oil and gas properties involving prior tax years.

(c) Net income (loss) available for common stock for the nine months ended September 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million.

(d) Net income (loss) available for common stock for the three and nine months ended September 30, 2016 and September 30, 2015 included incremental, non-recurring acquisition costs, after-tax of $4.0 million and $24 million, and $2.8 million and $3.0 million, respectively, and after-tax internal labor costs attributable to the acquisition of $1.7 million and $7.4 million, and $1.2 million and $1.8 million respectively. See Note 2 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(e) Net income (loss) available for common stock for the nine months ended September 30, 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced milder and hotter weather, respectively, during the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015. Cooling degree days were 3% lower and 8% higher, respectively for the three and nine months ended September 30, 2016, compared to the same periods in 2015. Cooling degree days for the three and nine months ended September 30, 2016 were 15% and 26% higher than normal, compared to 19% and 16% higher than normal for the same periods in 2015.

- On May 3, 2016, Colorado Electric filed a request with the Colorado Public Utilities Commission to increase its annual revenues by $8.9 million to recover investments in a $65 million, 40 MW natural gas-fired combustion turbine, currently under construction. Construction on the turbine continued in the third quarter of 2016. Through September 30, 2016, approximately $56 million was expended, and the project is on schedule to be completed and placed into service in the fourth quarter of 2016. Construction riders related to the project increased gross margins by approximately $1.6 million and $3.8 million for the three and nine months ended September 30, 2016, respectively. Hearings were held regarding this matter in October 2016 and we expect new rates to be effective January 1, 2017.

- During the first quarter of 2016, South Dakota Electric commenced construction of 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.

- On June 23, 2015, Colorado Electric filed for a CPCN with the CPUC to acquire the planned $109 million, 60 MW Peak View Wind Project, to be located near Colorado Electric's Busch Ranch wind farm. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. On October 21, 2015, the Commission approved a build transfer proposal and settlement agreement. The settlement provides for recovery of the costs of the project through Colorado Electric's Electric Cost Adjustments and Renewable Energy Standard Surcharge for 10 years, after which Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility. Colorado Electric will purchase the project for approximately $109 million through progress payments throughout 2016, with ownership transfer occurring just before achieving commercial operation. The project is being built by Invenergy Wind Development Colorado LLC and all 34 turbines have been constructed and tested. Commercial operation is expected in the fourth quarter of 2016. Through September 30, 2016, approximately $96 million was expended on the project.

Gas Utilities Segment

- Gas Utilities experienced cooler and milder weather, respectively, during the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015. Heating degree days were 147% higher and 17% lower, respectively, for the three and nine months ended September 30, 2016, compared to the same periods in 2015. Heating degree days for the three and nine months ended September 30, 2016 were 35% higher and 9% lower than normal, respectively, compared to 57% and 2% lower than normal for the same periods in 2015.

- During the third quarter of 2016, the Company withdrew its Cost of Service Gas applications in Wyoming, Iowa, Kansas and South Dakota. In consideration of the July 19, 2016 denial of the application from the NPSC and the April 2016 dismissal of its application from the CPUC, the Company is re-evaluating its Cost of Service Gas regulatory approval strategy.

  The Company's initial applications submitted in late 2015 were based on a two-phase approach, the first of which would establish the criteria for how the program would work, and the second would seek approval for a specific gas reserves property. The orders in Colorado and Nebraska indicated the initial phase filings contained insufficient information and data to support customer benefits. Based on pre-hearing discovery and commission orders, the Company is considering filing new applications for approval of specific gas reserve properties.

Power Generation Segment

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

Oil and Gas Segment

- Our Oil and Gas segment was impacted by lower net hedged prices received for crude oil and natural gas for the three and nine months ended September 30, 2016 compared to the same periods in 2015. The average hedged price received for natural gas decreased by 4% and 32%, respectively, for the three and nine months ended September 30, 2016 compared to the same periods in 2015. The average hedged price received for oil decreased by 3% and 14%, respectively, for the three and nine months ended September 30, 2016 compared to the same periods in 2015. Oil and Gas production volumes increased 5% and 0%, respectively, for the three and nine months ended September 30, 2016 compared to the same periods in 2015.

- Oil and Gas results benefited by $5.8 million from a change in estimate related to income taxes. The tax benefit relates to additional percentage depletion deductions that are being claimed with respect to the oil and gas properties. The benefit recorded in the first quarter of 2016 includes a change in estimate recorded for income tax accounting purposes. This benefit was the result of completion of a study to analyze prior depletion claimed dating back to 2007.

- We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis, known as a ceiling test. For the three and nine months ended September 30, 2016, our Oil and Gas segment recorded pre-tax, non-cash ceiling test impairments of $12 million and $38 million, respectively as a result of continued low commodity prices. We also recorded a $14 million impairment of other Oil and Gas depreciable properties not included in our full cost pool during the second quarter of 2016 as we decided to divest non-core oil and gas assets.

Corporate Activities

- On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046. The proceeds of the notes were used for the following:

    - Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;

    - Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;

    - Repay the remaining $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;

    - Pay down $100 million of the $500 million three-year unsecured term loan discussed below;

    - Payment of $29 million for the settlement of $400 million notional interest rate swaps; and

    - Remainder was used for general corporate purposes.

- On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan was used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017.

- 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. The facility 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 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options, which are substantially the same as the former agreement.

- During the first quarter of 2016, we reached an agreement in principle with IRS Appeals with respect to our liability for unrecognized tax benefits attributable to the like-kind exchange effectuated in connection with the 2008 IPP Transaction and the 2008 Aquila Transaction. This agreement resulted in a tax benefit of approximately $5.1 million in the first quarter of 2016. See Note 21 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q for additional details on this agreement.

- 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. During the three months ended September 30, 2016, we issued 819,442 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through September 30, 2016, we have sold and issued an aggregate of 1,750,091 shares of common stock under the ATM equity offering program for $106 million, net of $1.1 million in commissions. Additionally, 38,781 shares for net proceeds of $2.4 million have been sold, but were not settled and are not considered issued and outstanding as of September 30, 2016.

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing. In June 2016 we agreed to and received a working capital adjustment of $11 million. SourceGas operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. We funded the majority of the SourceGas Transaction with the following financings:

    - On January 13, 2016, we completed a public debt offering of $550 million in senior unsecured notes. The debt offering consisted of $300 million of 3.95%, 10-year senior notes due 2026, and $250 million of 2.50%, 3-year senior notes due 2019. Net proceeds after discounts and fees were approximately $546 million; and

    - On November 23, 2015, we completed the offerings of common stock and equity units. We issued 6.325 million shares of common stock for net proceeds of $246 million and 5.98 million equity units for net proceeds of $290 million.

- On February 12, 2016, Moody's affirmed the BHC credit rating of Baa1 and maintained a negative outlook following our acquisition of SourceGas. Moody’s maintained a negative outlook while monitoring BHC’s progress toward integrating the SourceGas assets subsequent to closing, consummating the sale of the 49.9% noncontrolling interest of our Colorado IPP assets and utilizing an ATM equity offering program. In addition, the negative outlook reflects overall weaker consolidated metrics when compared to historical ranges.

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

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

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

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 revenues less cost of natural gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

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

Electric Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue	$ 174,501	$ 178,590	$ (4,089)	$ 503,258	$ 512,530	$ (9,272)
Total fuel and purchased power	66,953	71,253	(4,300)	194,477	203,128	(8,651)
Gross margin	107,548	107,337	211	308,781	309,402	(621)
Operations and maintenance	38,108	40,538	(2,430)	116,312	122,509	(6,197)
Depreciation and amortization	21,063	20,122	941	62,794	60,344	2,450
Total operating expenses	59,171	60,660	(1,489)	179,106	182,853	(3,747)
Operating income	48,377	46,677	1,700	129,675	126,549	3,126
Interest expense, net	(12,046)	(12,455)	409	(36,676)	(38,670)	1,994
Other income (expense), net	1,335	806	529	2,828	1,047	1,781
Income tax benefit (expense)	(13,485)	(12,369)	(1,116)	(33,202)	(31,082)	(2,120)
Net income (loss)	$ 24,181	$ 22,659	$ 1,522	$ 62,625	$ 57,844	$ 4,781

Revenue - Electric (in thousands)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Residential:				
South Dakota Electric	$ 17,501	$ 18,471	$ 53,057	$ 54,081
Wyoming Electric	9,585	9,837	29,283	29,031
Colorado Electric	27,460	27,586	73,721	74,303
Total Residential	54,546	55,894	156,061	157,415
Commercial:				
South Dakota Electric	25,714	27,156	73,026	76,330
Wyoming Electric	16,306	16,991	47,818	48,550
Colorado Electric	25,907	24,649	72,782	70,368
Total Commercial	67,927	68,796	193,626	195,248
Industrial:				
South Dakota Electric	8,275	8,364	24,540	25,122
Wyoming Electric	11,904	9,493	32,353	26,657
Colorado Electric	9,870	10,885	28,917	32,041
Total Industrial	30,049	28,742	85,810	83,820
Municipal:				
South Dakota Electric	1,053	1,024	2,844	2,741
Wyoming Electric	543	552	1,606	1,650
Colorado Electric	3,299	3,173	8,879	9,191
Total Municipal	4,895	4,749	13,329	13,582
Total Retail Revenue - Electric	157,417	158,181	448,826	450,065
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric	4,596	4,563	12,717	13,962
Off-system Wholesale:				
South Dakota Electric	3,984	5,417	11,304	18,718
Wyoming Electric	924	854	3,777	3,807
Colorado Electric	522	515	1,229	1,017
Total Off-system Wholesale	5,430	6,786	16,310	23,542
Other Revenue:				
South Dakota Electric	5,605	7,116	19,901	19,478
Wyoming Electric	325	659	1,435	1,700
Colorado Electric	1,128	1,285	4,069	3,783
Total Other Revenue	7,058	9,060	25,405	24,961
Total Revenue - Electric	$ 174,501	$ 178,590	$ 503,258	$ 512,530

Quantities Generated and Purchased (in MWh)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Generated —				
Coal-fired:				
South Dakota Electric [(a)]	401,231	389,784	1,054,264	1,166,381
Wyoming Electric [(b)]	188,739	142,887	548,513	517,685
Total Coal-fired	589,970	532,671	1,602,777	1,684,066
Natural Gas and Oil:				
South Dakota Electric [(a)]	41,654	37,721	96,649	57,482
Wyoming Electric [(a)]	23,874	24,331	58,944	34,881
Colorado Electric	64,507	49,343	128,397	87,090
Total Natural Gas and Oil	130,035	111,395	283,990	179,453
Wind:				
Colorado Electric	10,676	8,884	34,325	28,152
Total Wind	10,676	8,884	34,325	28,152
Total Generated:				
South Dakota Electric	442,885	427,505	1,150,913	1,223,863
Wyoming Electric	212,613	167,218	607,457	552,566
Colorado Electric	75,183	58,227	162,722	115,242
Total Generated	730,681	652,950	1,921,092	1,891,671
Purchased —				
South Dakota Electric	247,097	307,984	902,166	1,097,319
Wyoming Electric	215,257	215,913	624,137	576,843
Colorado Electric	527,947	543,432	1,473,195	1,470,478
Total Purchased	990,301	1,067,329	2,999,498	3,144,640
Total Generated and Purchased:				
South Dakota Electric	689,982	735,489	2,053,079	2,321,182
Wyoming Electric	427,870	383,131	1,231,594	1,129,409
Colorado Electric	603,130	601,659	1,635,917	1,585,720
Total Generated and Purchased	1,720,982	1,720,279	4,920,590	5,036,311

(a) An increase in gas-fired generation from Cheyenne Prairie was due to lower coal fired generation driven by outages at the coal-fired Wyodak plant during the nine months ended September 30, 2016.

(b) Increase was due to a planned annual outage at Wygen II during the three months ended September 30, 2015.

Quantity Sold (in MWh)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Residential:				
South Dakota Electric	124,012	128,474	381,616	385,454
Wyoming Electric	63,505	63,410	191,405	189,078
Colorado Electric	176,900	178,786	470,246	472,767
Total Residential	364,417	370,670	1,043,267	1,047,299
Commercial:				
South Dakota Electric	213,276	218,305	592,371	603,272
Wyoming Electric	137,534	138,841	398,414	400,400
Colorado Electric	211,716	197,717	572,062	532,306
Total Commercial	562,526	554,863	1,562,847	1,535,978
Industrial:				
South Dakota Electric	110,220	109,725	320,861	324,078
Wyoming Electric	175,188	131,785	468,262	361,061
Colorado Electric (a)	116,073	132,190	329,016	361,222
Total Industrial	401,481	373,700	1,118,139	1,046,361
Municipal:				
South Dakota Electric	9,927	9,322	25,855	24,058
Wyoming Electric	2,201	2,334	6,848	7,058
Colorado Electric	34,507	34,860	91,116	91,781
Total Municipal	46,635	46,516	123,819	122,897
Total Retail Quantity Sold	1,375,059	1,345,749	3,848,072	3,752,535
Contract Wholesale:				
Total Contract Wholesale - South Dakota Electric (b)	62,547	65,952	182,087	215,119
Off-system Wholesale:				
South Dakota Electric	128,415	154,215	438,852	646,066
Wyoming Electric	18,788	18,558	77,534	92,092
Colorado Electric (c)	17,949	16,071	53,644	32,041
Total Off-system Wholesale	165,152	188,844	570,030	770,199
Total Quantity Sold:				
South Dakota Electric	648,397	685,993	1,941,642	2,198,047
Wyoming Electric	397,216	354,928	1,142,463	1,049,689
Colorado Electric	557,145	559,624	1,516,084	1,490,117
Total Quantity Sold	1,602,758	1,600,545	4,600,189	4,737,853
Other Uses, Losses or Generation, net (d):				
South Dakota Electric	41,585	49,496	111,437	123,135
Wyoming Electric	30,654	28,203	89,131	79,720
Colorado Electric	45,985	42,035	119,833	95,603
Total Other Uses, Losses and Generation, net	118,224	119,734	320,401	298,458
Total Energy	1,720,982	1,720,279	4,920,590	5,036,311

(a) Decrease for the three and nine months ended September 30, 2016 was due to outages at large industrial customers.
(b) Decrease was driven by load requirements related to a unit-contingent PPA during the nine months ended September 30, 2016.
(c) Increase in 2016 generation was primarily driven by commodity prices that impacted power marketing sales.
(d) Includes company uses, line losses, and excess exchange production.

Degree Days	Three Months Ended September 30, 2016			2015	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	161	(23)%	27%	127	(40)%
Wyoming Electric	210	(19)%	78%	118	(57)%
Colorado Electric	20	(77)%	400%	4	(95)%
Combined [(a)]	107	(34)%	53%	70	(58)%
Cooling Degree Days:					
South Dakota Electric	460	(18)%	(4)%	477	(15)%
Wyoming Electric	358	19 %	4%	343	14 %
Colorado Electric	968	33 %	(5)%	1,015	39 %
Combined [(a)]	673	15 %	(3)%	697	19 %

Degree Days	Nine Months Ended September 30, 2016			2015	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	3,844	(13)%	(4)%	4,005	(10)%
Wyoming Electric	4,120	(12)%	5%	3,942	(12)%
Colorado Electric	2,821	(15)%	(7)%	3,026	(8)%
Combined [(a)]	3,430	(13)%	(3)%	3,543	(10)%
Cooling Degree Days:					
South Dakota Electric	646	(3)%	13%	573	(14)%
Wyoming Electric	460	31 %	14%	405	15 %
Colorado Electric	1,337	40 %	6%	1,260	32 %
Combined [(a)]	926	26 %	8%	855	16 %

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

Electric Utilities Power Plant Availability	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Coal-fired plants [(a)]	94.8%	89.0%	88.0%	92.2%
Other plants	98.4%	96.4%	97.0%	95.3%
Total availability	97.1%	93.7%	93.7%	94.2%

(a) Decrease is due to a planned outage at Wygen III and an extended planned outage at Wyodak during the nine months ended September 30, 2016.

Results of Operations for the Electric Utilities for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015: Net income available for common stock for the Electric Utilities was $24 million for the three months ended September 30, 2016, compared to Net income available for common stock of $23 million for the three months ended September 30, 2015, as a result of:

Gross margin was comparable to the prior year reflecting a $0.8 million increase in our construction and TCA rider margins and an increase of $0.8 million in commercial and industrial margins driven by increased demand compared to the same period in the prior year. Partially offsetting these increases were lower residential margins of $0.6 million driven primarily by lower residential megawatt hours sold and a decrease in cooling degree days which were 3 percent lower than the prior year and 15 percent higher than normal.

Operations and maintenance decreased primarily due to lower generation and major maintenance expenses of $1.4 million primarily as a result of outage timing differences compared to the same period in the prior year and $0.9 million driven by a change in expense allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities.

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

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

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

Results of Operations for the Electric Utilities for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015: Net income available for common stock for the Electric Utilities was $63 million for the nine months ended September 30, 2016, compared to Net income available for common stock of $58 million for the nine months ended September 30, 2015, as a result of:

Gross margin was comparable to the same period in the prior year reflecting increased rider margins of $3.5 million driven primarily by our construction and TCA riders, an increase of $1.5 million in residential margins driven by favorable weather and a $0.8 million increase in energy efficiency margin recovery. Offsetting these increases was a $2.1 million benefit in the prior year as a result of a one-time settlement agreement from the CPUC on our renewable energy standard adjustment related to the Busch Ranch wind farm, a prior year increase in return on invested capital of $1.2 million from South Dakota Electric’s rate case, a $1.2 million decrease driven by lower residential usage per customer and a $1.3 million decrease due to third party billing true-ups relating to the current and prior years.

Operations and maintenance decreased primarily due to $4.2 million of lower employee costs driven by a change in expense allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities; additional lower pension related costs of $1.3 million primarily due to discount rate and changes in the yield curve methodology; and lower generation and major maintenance expenses of $0.9 million compared to the same period in the prior year.

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

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

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

Gas Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$ 123,825	$ 67,794	$ 56,031	$ 516,302	$ 393,739	$ 122,563
Other — non-regulated services	17,620	7,361	10,259	47,577	23,211	24,366
Total revenue	141,445	75,155	66,290	563,879	416,950	146,929
Cost of sales						
Natural gas — regulated	29,320	24,613	4,707	202,243	220,495	(18,252)
Other — non-regulated services	12,410	4,072	8,338	25,756	11,556	14,200
Total cost of sales	41,730	28,685	13,045	227,999	232,051	(4,052)
Gross margin	99,715	46,470	53,245	335,880	184,899	150,981
Operations and maintenance	64,921	33,689	31,232	179,845	105,834	74,011
Depreciation and amortization	21,193	8,102	13,091	57,096	23,867	33,229
Total operating expenses	86,114	41,791	44,323	236,941	129,701	107,240
Operating income (loss)	13,601	4,679	8,922	98,939	55,198	43,741
Interest expense, net	(21,267)	(4,263)	(17,004)	(53,858)	(12,829)	(41,029)
Other income (expense), net	(418)	46	(464)	(28)	53	(81)
Income tax benefit (expense)	5,128	190	4,938	(15,065)	(14,947)	(118)
Net income (loss)	(2,956)	652	(3,608)	29,988	27,475	2,513
Net (income) loss attributable to noncontrolling interest	17	—	17	(13)	—	(13)
Net income (loss) available for common stock	$ (2,939)	$ 652	$ (3,591)	$ 29,975	$ 27,475	$ 2,500

The following table summarizes our system infrastructure updated to include our acquired SourceGas utilities:

System Infrastructure (in line miles) as of September 30, 2016	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	886	4,572	906
Colorado	678	6,481	2,323
Nebraska	1,249	8,330	3,319
Iowa	180	2,740	2,639
Kansas	293	2,826	1,328
Wyoming	1,299	3,375	1,208
Total	4,585	28,324	11,723

Revenue (in thousands)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Residential:				
Arkansas	$ 8,201	$ —	$ 33,778	$ —
Colorado	12,144	5,343	65,285	40,940
Nebraska	17,027	12,694	83,875	84,766
Iowa	9,694	10,461	57,328	69,805
Kansas	7,760	7,556	39,428	45,698
Wyoming	7,377	3,133	32,050	16,386
Total Residential	$ 62,203	$ 39,187	$ 311,744	$ 257,595
Commercial:				
Arkansas	$ 4,414	$ —	$ 16,850	$ —
Colorado	5,037	1,223	23,200	8,147
Nebraska	3,123	2,897	19,462	25,004
Iowa	3,144	3,778	22,617	30,301
Kansas	2,298	2,382	12,558	16,440
Wyoming	2,321	1,672	11,500	9,039
Total Commercial	$ 20,337	$ 11,952	$ 106,187	$ 88,931
Industrial:				
Arkansas	$ 1,171	$ —	$ 2,755	$ —
Colorado	742	1,058	1,247	1,305
Nebraska	143	389	330	1,288
Iowa	189	225	1,014	1,923
Kansas	5,204	7,464	7,793	11,961
Wyoming	685	570	2,342	3,004
Total Industrial	$ 8,134	$ 9,706	$ 15,481	$ 19,481
Transportation:				
Arkansas	$ 2,016	$ —	$ 5,774	$ —
Colorado	1,254	124	4,079	727
Nebraska	18,454	2,128	34,405	9,955
Iowa	970	849	3,525	3,548
Kansas	1,736	1,693	5,134	5,624
Wyoming	2,122	789	7,171	2,295
Total Transportation	$ 26,552	$ 5,583	$ 60,088	$ 22,149

Revenue (in thousands) (continued)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Transmission:				
Arkansas	$ —	$ —	$ —	$ —
Colorado	3,324	—	11,305	—
Nebraska	121	—	327	—
Iowa	—	—	—	—
Kansas	—	—	—	—
Wyoming	295	—	1,269	—
Total Transmission	$ 3,740	$ —	$ 12,901	$ —
Other Sales Revenue:				
Arkansas	$ 398	$ —	$ 1,805	$ —
Colorado	80	25	262	441
Nebraska	912	501	2,586	1,771
Iowa	96	120	409	467
Kansas	582	666	3,215	2,692
Wyoming	791	57	1,624	215
Total Other Sales Revenue	$ 2,859	$ 1,369	$ 9,901	$ 5,586
Total Regulated Revenue	$ 123,825	$ 67,797	$ 516,302	$ 393,742
Non-regulated Services	17,620	7,358	47,577	23,208
Total Revenue	$ 141,445	$ 75,155	$ 563,879	$ 416,950

Gross Margin (in thousands)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Residential:				
Arkansas	$ 6,735	$ —	$ 24,116	$ —
Colorado	7,235	2,892	28,531	12,918
Nebraska	13,982	9,023	52,377	37,729
Iowa	8,252	8,277	30,848	30,989
Kansas	5,872	5,836	22,401	23,518
Wyoming	6,345	2,435	23,551	8,958
Total Residential	$ 48,421	$ 28,463	$ 181,824	$ 114,112
Commercial:				
Arkansas	$ 2,842	$ —	$ 9,793	$ —
Colorado	2,451	482	8,705	2,096
Nebraska	1,652	1,493	7,865	7,876
Iowa	1,894	1,903	8,351	8,656
Kansas	1,289	1,348	5,300	6,228
Wyoming	1,223	780	5,601	3,099
Total Commercial	$ 11,351	$ 6,006	$ 45,615	$ 27,955

Gross Margin (in thousands) (continued)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Industrial:				
Arkansas	$ 290	$ —	$ 952	$ —
Colorado	260	251	501	341
Nebraska	54	130	149	369
Iowa	40	41	127	172
Kansas	985	1,280	1,753	2,230
Wyoming	157	58	507	403
Total Industrial	$ 1,786	$ 1,760	$ 3,989	$ 3,515
Transportation:				
Arkansas	$ 2,016	$ —	$ 5,774	$ —
Colorado	1,036	124	3,850	727
Nebraska	18,454	2,128	34,405	9,955
Iowa	970	849	3,525	3,548
Kansas	1,736	1,693	5,134	5,624
Wyoming	2,122	789	7,171	2,295
Total Transportation	$ 26,334	$ 5,583	$ 59,859	$ 22,149
Transmission:				
Arkansas	$ —	$ —	$ —	$ —
Colorado	3,324	—	11,297	—
Nebraska	121	—	327	—
Iowa	—	—	—	—
Kansas	—	—	—	—
Wyoming	295	—	1,245	—
Total Transmission	$ 3,740	$ —	$ 12,869	$ —
Other Sales Margins:				
Arkansas	$ 398	$ —	$ 1,805	$ —
Colorado	81	23	262	440
Nebraska	912	501	2,586	1,771
Iowa	96	120	409	467
Kansas	595	669	3,217	2,621
Wyoming	791	57	1,624	215
Total Other Sales Margins	$ 2,873	$ 1,370	$ 9,903	$ 5,514
Total Regulated Gross Margin	$ 94,505	$ 43,182	$ 314,059	$ 173,245
Non-regulated Services	5,210	3,288	21,821	11,654
Total Gross Margin	$ 99,715	$ 46,470	$ 335,880	$ 184,899

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Residential:				
Arkansas	531,564	—	3,277,167	—
Colorado	1,067,081	456,779	8,012,982	4,453,521
Nebraska	973,977	713,809	9,399,255	7,820,461
Iowa	478,158	499,839	6,744,086	7,061,074
Kansas	416,971	396,855	4,071,723	4,346,965
Wyoming	537,877	163,695	4,660,039	1,573,852
Total Residential	4,005,628	2,230,977	36,165,252	25,255,873
Commercial:				
Arkansas	568,901	—	2,392,270	—
Colorado	539,304	143,356	2,977,764	979,082
Nebraska	384,546	287,698	2,800,616	2,911,344
Iowa	423,084	430,914	3,725,512	3,996,378
Kansas	220,650	241,909	1,771,050	2,011,756
Wyoming	382,503	187,272	2,194,605	1,256,089
Total Commercial	2,518,988	1,291,149	15,861,817	11,154,649
Industrial:				
Arkansas	263,946	—	606,942	—
Colorado	212,997	212,080	341,325	258,017
Nebraska	29,531	85,937	62,243	239,262
Iowa	52,092	42,396	243,902	321,178
Kansas [(a)]	1,645,891	2,092,545	2,575,314	3,118,446
Wyoming	185,299	70,276	673,331	490,334
Total Industrial	2,389,756	2,503,234	4,503,057	4,427,237
Wholesale and Other:				
Arkansas	—	—	29,640	—
Colorado	—	—	—	—
Nebraska	—	—	—	—
Iowa	—	—	—	—
Kansas [(a)]	—	—	—	14,902
Wyoming	—	—	—	—
Total Wholesale and Other	—	—	29,640	14,902
Total Distribution Quantities Sold	8,914,372	6,025,360	56,559,766	40,852,661
Transportation:				
Arkansas	2,225,478	—	5,774,790	—
Colorado	668,591	99,086	2,267,404	709,572
Nebraska	14,869,342	6,428,867	36,700,292	21,987,850
Iowa	4,394,260	4,295,910	14,860,343	14,983,598
Kansas	4,598,060	3,902,116	11,646,066	11,763,592
Wyoming	4,504,909	2,530,445	15,485,987	8,416,863
Total Transportation	31,260,640	17,256,424	86,734,882	57,861,475
Total Distribution Quantities Sold and Transportation	40,175,012	23,281,784	143,294,648	98,714,136

(a) Change from prior year due to a change in Wholesale customer classification to Industrial classification.

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 state in which our Gas Utilities operate, the winter heating season begins around November 1 and ends around March 31.

	Three Months Ended September 30,				
	2016			2015	
Heating Degree Days: [c]	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a] [d]	9	N/A	N/A	—	—%
Colorado	153	22%	273%	41	(77)%
Nebraska	191	127%	446%	35	64%
Iowa	68	(51)%	(20)%	85	(39)%
Kansas [a]	26	(54)%	100%	13	(76)%
Wyoming	314	27%	166%	118	(57)%
Combined [b]	146	35%	147%	59	(57)%

	Nine Months Ended September 30,				
	2016			2015	
Heating Degree Days: [c]	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a]	1,198	(6)%	N/A	—	— %
Colorado	3,670	(6)%	6%	3,463	(11)%
Nebraska	3,312	(13)%	(6)%	3,523	(5)%
Iowa	3,783	(11)%	(17)%	4,568	9 %
Kansas [a]	2,596	(13)%	(5)%	2,738	(8)%
Wyoming	4,334	(7)%	10%	3,942	(12)%
Combined [b]	3,215	(9)%	(17)%	3,891	(2)%

(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins. Arkansas has a weather normalization mechanism in effect during the months of November through April and is included for those customers with residential and business rate schedules. 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.
(c) The combined 2015 variance from 30-Year Average reflects the inclusion of Cheyenne Light's natural gas utility operations.
(d) Comparison to normal is not a meaningful measure due to the HDD seasonality in Arkansas. 1 HDD is the Normal for the three months ended September 30, 2016 in Arkansas.

Results of Operations for the Gas Utilities for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015: Net loss available for common stock for the Gas Utilities was $3.0 million for the three months ended September 30, 2016, compared to Net income available for common stock of $0.7 million for the three months ended September 30, 2015, as a result of:

Gross margin increased primarily due to margins of approximately $53 million contributed by the SourceGas utilities acquired on Feb. 12, 2016.

Operations and maintenance increased primarily due to additional operating costs of approximately $31 million for the acquired SourceGas utilities. Partially offsetting this increase were lower employee costs of $1.2 million driven by a change in expense allocations impacting the gas utilities as a result of integrating the acquired SourceGas utilities.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities of approximately $13 million, and due to a higher asset base at our other utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $17 million 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, including the impact of the acquired SourceGas utilities, reflects additional tax benefits related primarily to a favorable tax return true-up and flow-through adjustments. Such adjustments were attributable to legacy gas utility operations.

Results of Operations for the Gas Utilities for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015: Net income available for common stock for the Gas Utilities was $30 million for the nine months ended September 30, 2016, compared to Net income available for common stock of $27 million for the nine months ended September 30, 2015, as a result of:

Gross margin increased primarily due to margins of approximately $152 million contributed by the SourceGas utilities acquired on February 12, 2016. An additional margin increase of $3.2 million was attributable to year-over-year customer growth primarily from our 2015 Wyoming gas system acquisitions. Partially offsetting these increases was a $2.6 million decrease due to weather. Heating degree days were 17% lower for the nine months ended September 30, 2016, compared to the same period in the prior year and 9% lower than normal in the current year, compared to 2% lower than normal in the prior year.

Operations and maintenance increased primarily due to additional operating costs of approximately $78 million for the acquired SourceGas utilities. Partially offsetting this increase were lower employee costs primarily due to a $5.2 million decrease driven by a change in expense allocations as a result of integrating the new SourceGas utilities.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities of approximately $32 million, and due to a higher asset base at our other utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $41 million 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, including the impact of the acquired SourceGas utilities, is comparable to the same period in the prior year.

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 2015 Annual Report on Form 10-K filed with the SEC.

Colorado Electric Rate Case filing

On May 3, 2016, Colorado Electric filed a rate request with the CPUC to increase annual revenues by $8.9 million to recover investments in the $65 million, 40 MW natural gas-fired combustion turbine, currently under construction. The filing seeks a return on equity of 9.83% and a capital structure of 50.92% equity and 49.08% debt. Hearings were held regarding this matter in October 2016 and we expect new rates to be effective January 1, 2017.

Black Hills Gas Holdings Regulatory Matters

The following table illustrates information about certain enacted regulatory provisions with respect to the states in which our acquired SourceGas utilities operate:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters
Arkansas Gas	AR	9.4%	6.47%(a)	52%/48%	$299.4(b)	2/2016	Gas Cost Adjustment, Main Replacement Program, At-Risk Meter Replacement Program, legislative/regulatory mandate and relocations rider, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	10%	8.02%	49.52%/50.48%	$127.1	12/2010	Gas Cost Adjustment, DSM
Nebraska Gas	NE	9.60%	7.67%	48.84%/51.16%	$87.6/$69.8(c)	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice supplier fee
Wyoming Gas	WY	9.92%	7.98%	49.66%/50.34%	$100.5	1/2011	Choice Gas Program, Purchased Gas Cost Adjustment, Usage Per Customer Adjustment
RMNG	CO	10.6%	7.93%	49.23%/50.77%	$90.5	3/2013	System Safety Integrity Rider, liquids/off-system/market center services Revenue Sharing

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(a) Arkansas return on rate base adjusted to remove current liabilities from rate case capital structure for comparison with other subsidiaries.
(b) Arkansas rate base adjusted to include current liabilities for comparison with other subsidiaries.
(c) Total Nebraska rate base of $87.6 million includes amounts allocated to serve non-jurisdictional and agricultural customers. Jurisdictional Nebraska rate base of $69.8 million excludes those amounts allocated to serve non-jurisdictional and agricultural customers and is used for calculation of jurisdictional base rates.

Some of the mechanisms in place at the Black Hills Gas Holdings utilities include the following:

- In Arkansas, we have tariff adjustment mechanisms for weather normalization and revenue erosion from a decline in billing determinants. We also have tariffs that allow more timely recovery of main replacements, at-risk meter replacements and expenditures due to legislative/regulatory mandates and relocations outside of a rate case.

- In Nebraska and for RMNG, we have a system safety and integrity rider that recovers forecast safety and integrity capital expenditure-related costs and operating and maintenance expenses.

- In Nebraska, we are allowed to recover uncollectible accounts expenses through a choice supplier fee.

- In Wyoming, we have a cost adjustment to recover lost revenue due to declining usage per customer and a rider to recover the cost of replacing above ground pipe.

The following summarizes Black Hills Gas Holdings' recent state and federal rate case and initial surcharge orders (in millions):

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Arkansas Gas [(a)]	Gas	4/2015	2/2016	$ 12.6	$ 8.0
RMNG[(b)]	Gas - transmission and storage	11/2015	1/2016	$ 1.5	$ 1.5
Nebraska Gas [(c)]	Gas	10/2016		$ 6.5	
Wyoming Gas [(d)]	Gas	2/2010	1/2011	$ 7.5	$ 4.3
Colorado Gas [(e)]	Gas	6/2010	12/2010	$ 6.0	$ 2.8

(a) In February 2016, Arkansas Gas implemented new base rates resulting in a revenue increase of $8.0 million. The APSC modified a stipulation reached between the APSC Staff and all intervenors except the Attorney General and Arkansas Gas in its order issued on January 28, 2016. The modified stipulation revised the capital structure to 52% debt and 48% equity and also limited recovery of portions of cost related to incentive compensation.

(b) On November 1, 2015, RMNG filed with the CPUC requesting recovery of $1.5 million related to system safety and integrity "SSIR" expenditures expected to be incurred in 2016. The SSIR rate was adjusted downward to reflect a true up of $0.7 million from the expenditure projection for 2014. The SSIR tariff was allowed to go into effect by operation of law on January 1, 2016.

(c) On October 3, 2016, Nebraska Gas 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. The SSIR tariff is scheduled for hearing on December 13, 2016 to go into effect on February 1, 2017.

(d) On January 1, 2011, Wyoming Gas implemented new base rates in accordance with the order by the WPSC issued on December 23, 2010. The approved rates were based upon an authorized return on equity of 9.92% and a capital structure of 49.66% debt and 50.34% equity. The rate increase represented a $4.3 million increase over existing rates.

(e) On December 1, 2010, the CPUC issued an order approving a stipulation to increase Colorado Gas base rates by $2.8 million. The stipulated rate increase was based upon an authorized return on equity of 10.00% and a capital structure of 49.23% debt and 50.77% equity. Increased rates became effective on December 3, 2010.

Cost of Service Gas Program Filings

On September 30, 2015, BHC's utility subsidiaries submitted applications with respective state utility regulators seeking approval for a Cost of Service Gas Program in Iowa, Kansas, Nebraska, South Dakota and Wyoming. An application was submitted in Colorado on November 2, 2015. The Cost of Service Gas Program is 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.

The Company's initial cost of service applications were developed during a two-year period with input from state regulatory commissioners, staff and consumer advocates to structure the program using a two-phase approach. The first phase would establish the criteria for how the program would work and the second phase would seek approval for a specific gas reserves property.

Hearings for approval of the Cost of Service Gas Program were conducted in Nebraska and Iowa in April and May, respectively. On July 19, 2016, the NPUC issued an order denying our application. In April, the CPUC dismissed without prejudice the Company's application. Orders from these two states indicated that the initial phase filings contained insufficient information and data to support customer benefits. Hearings were scheduled for Wyoming in August 2016, and for Kansas and South Dakota in September 2016. On July 26, 2016 the Company announced it requested a withdrawal of proceedings for its Cost of Service Gas application in Wyoming and subsequently withdrew its applications in Iowa, Kansas and South Dakota. Based on pre-hearing discovery and the two commission orders, the Company is considering filing new applications for approval of specific gas reserve properties.

Power Generation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue [(a)]	$ 23,337	$ 23,251	$ 86	$ 68,359	$ 68,234	$ 125
Operations and maintenance	7,465	7,456	9	24,155	23,767	388
Depreciation and amortization [(a)]	996	1,078	(82)	3,080	3,327	(247)
Total operating expense	8,461	8,534	(73)	27,235	27,094	141
Operating income	14,876	14,717	159	41,124	41,140	(16)
Interest expense, net	(409)	(753)	344	(1,343)	(2,427)	1,084
Other (expense) income, net	(9)	35	(44)	(5)	40	(45)
Income tax (expense) benefit	(5,046)	(4,932)	(114)	(13,467)	(13,992)	525
Net income (loss)	9,412	9,067	345	26,309	24,761	1,548
Net income attributable to noncontrolling interest	(3,770)	—	(3,770)	(6,402)	—	(6,402)
Net income (loss) available for common stock	$ 5,642	$ 9,067	$ (3,425)	$ 19,907	$ 24,761	$ (4,854)

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

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Net income available for common stock for the three and nine months ended September 30, 2016, was reduced by $3.8 million and $6.4 million, respectively, attributable to this noncontrolling interest.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Quantities Sold, Generated and Purchased (MWh) [(a)]				
Sold				
Black Hills Colorado IPP	327,793	310,689	972,113	862,540
Black Hills Wyoming [(b)]	167,670	172,807	476,677	497,922
Total Sold	495,463	483,496	1,448,790	1,360,462
Generated				
Black Hills Colorado IPP	327,793	310,689	972,113	862,540
Black Hills Wyoming	142,388	143,728	401,292	420,968
Total Generated	470,181	454,417	1,373,405	1,283,508
Purchased				
Black Hills Wyoming [(b)]	23,558	30,336	68,797	67,827
Total Purchased	23,558	30,336	68,797	67,827

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Contracted power plant fleet availability:				
Coal-fired plant [(a)]	98.7%	98.9%	94.1%	98.2%
Natural gas-fired plants	99.1%	99.2%	99.2%	99.0%
Total availability	99.0%	99.1%	97.9%	98.8%

(a) Decrease due to a planned outage on Wygen I during the nine months ended September 30, 2016.

Results of Operations for Power Generation for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015: Net income available for common stock for the Power Generation segment was $5.6 million for the three months ended September 30, 2016, compared to Net income available for common stock of $9.1 million for the same period in 2015 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 driven by 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: The effective tax rate was comparable to the same period in the prior year.

Net income attributable to noncontrolling interest: Net income attributable to noncontrolling interest increased by $3.8 million as a result of the noncontrolling interest sale in April 2016.

Results of Operations for Power Generation for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015: Net income available for common stock for the Power Generation segment was $20 million for the nine months ended September 30, 2016, compared to Net income available for common stock of $25 million for the same period in 2015 as a result of:

Revenue was comparable to the same prior year reflecting an increase in PPA pricing and an increase in MWh sold, offset by a decrease in contracted revenue driven by the Wygen I plant outage in the second quarter of 2016.

Operations and maintenance was comparable to the same period in the prior year reflecting higher maintenance fees driven by current year outages, partially offset by lower outside services.

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

Interest expense, net decreased due to higher interest income driven by 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: The effective tax rate is lower than the same period in the prior year due to the effect of the current period noncontrolling interest. Black Hills Colorado IPP went from a single member LLC, wholly owned by Black Hills Electric Generations, to a partnership as a result of the sale of 49.9 % of its membership interest in April 2016.

Net income attributable to noncontrolling interest: Net income attributable to noncontrolling interest increased by $6.4 million as a result of the noncontrolling interest sale in April 2016.

Mining

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
			(in thousands)			
Revenue	$ 16,820	$ 16,966	$ (146)	$ 44,149	$ 49,625	$ (5,476)
Operations and maintenance	10,465	10,841	(376)	29,186	31,406	(2,220)
Depreciation, depletion and amortization	2,342	2,484	(142)	7,269	7,448	(179)
Total operating expenses	12,807	13,325	(518)	36,455	38,854	(2,399)
Operating income (loss)	4,013	3,641	372	7,694	10,771	(3,077)
Interest (expense) income, net	(100)	(98)	(2)	(283)	(289)	6
Other income, net	559	567	(8)	1,625	1,700	(75)
Income tax benefit (expense)	(1,165)	(1,063)	(102)	(2,067)	(3,076)	1,009
Net income (loss)	$ 3,307	$ 3,047	$ 260	$ 6,969	$ 9,106	$ (2,137)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Tons of coal sold	1,106	1,041	2,722	3,136
Cubic yards of overburden moved [(a)]	2,065	1,747	5,516	4,552
Revenue per ton	$ 15.20	$ 16.30	$ 16.21	$ 15.82

(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 September 30, 2016 Compared to the Three Months Ended September 30, 2015: Net income available for common stock for the Mining segment was $3.3 million for the three months ended September 30, 2016, compared to Net income available for common stock of $3.0 million for the same period in 2015 as a result of:

Revenue was comparable to the same period in the prior year reflecting a 6% increase in tons sold, partially offset by a 7% 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, compared to approximately 45 percent in the same period of the prior year.

Operations and maintenance decreased primarily due to lower major maintenance requirements.

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.

Results of Operations for Mining for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015: Net income available for common stock for the Mining segment was $7.0 million for the nine months ended September 30, 2016, compared to Net income available for common stock of $9.1 million for the same period in 2015 as a result of:

Revenue decreased primarily due to a 13% decrease in tons sold due to a planned five-week outage in the second quarter of 2016, which was extended by an additional six weeks at the Wyodak plant due to an unplanned major repair of a turbine rotor, as well as lower sales to other generating plants, partially offset by a 2% increase in price per ton sold. The increase in price per ton sold was driven by contract price adjustments based on actual mining costs. Approximately 50% of the mine's production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance decreased primarily due lower royalties and production taxes on reduced revenues, lower fuel costs and lower employee costs, partially offset by mining in areas with higher overburden.

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 lower than the same period in the prior year due to the impact of the tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Variance	2016	2015	Variance
	(in thousands)					
Revenue	$ 9,639	$ 9,895	$ (256)	$ 25,660	$ 33,481	$ (7,821)
Operations and maintenance	7,592	10,963	(3,371)	24,539	32,868	(8,329)
Depreciation, depletion and amortization	3,483	6,151	(2,668)	11,415	22,452	(11,037)
Impairment of long-lived assets	12,293	61,875	(49,582)	52,286	178,395	(126,109)
Total operating expenses	23,368	78,989	(55,621)	88,240	233,715	(145,475)
Operating income (loss)	(13,729)	(69,094)	55,365	(62,580)	(200,234)	137,654
Interest income (expense), net	(1,295)	(714)	(581)	(3,529)	(1,576)	(1,953)
Other income (expense), net	16	(163)	179	85	(379)	464
Impairment of equity investments	—	—	—	—	(5,170)	5,170
Income tax benefit (expense)	6,180	30,202	(24,022)	30,747	77,280	(46,533)
Net income (loss)	$ (8,828)	$ (39,769)	$ 30,941	$ (35,277)	$ (130,079)	$ 94,802

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Production:				
Bbls of oil sold	89,569	98,722	263,788	278,357
Mcf of natural gas sold	2,426,892	2,271,186	7,148,952	7,226,949
Bbls of NGL sold	27,640	19,342	105,535	81,383
Mcf equivalent sales	3,130,147	2,979,568	9,364,891	9,385,391

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Average price received: [(a) (b)]				
Oil/Bbl	$ 56.64	$ 58.31	$ 54.38	$ 63.20
Gas/Mcf	$ 1.63	$ 1.69	$ 1.28	$ 1.89
NGL/Bbl	$ 11.31	$ 2.87	$ 10.95	$ 13.64
Depletion expense/Mcfe	$ 0.81	$ 1.64	$ 0.86	$ 2.03

(a) Net of hedge settlement gains and losses.
(b) Pre-tax impairments of long-lived Oil and Gas properties of $12 million and $52 million, and $62 million and $178 million were recorded for the three and nine months ended September 30, 2016 and September 30, 2015, respectively.

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

Producing Basin	Three Months Ended September 30, 2016 LOE	Gathering, Compression, Processing and Transportation [a]	Production Taxes	Total	Three Months Ended September 30, 2015 LOE	Gathering, Compression, Processing and Transportation [a]	Production Taxes	Total
San Juan	$ 1.69	$ 1.19	$ 0.38	$ 3.26	$ 1.10	$ 1.01	$ 0.11	$ 2.22
Piceance	0.24	1.84	0.16	2.24	0.80	2.29	0.31	3.40
Powder River	1.89	—	0.20	2.09	1.57	—	0.56	2.13
Williston	0.84	—	1.64	2.48	1.59	—	0.62	2.21
All other properties	0.30	—	0.22	0.52	1.16	—	0.27	1.43
Total weighted average	$ 0.84	$ 1.19	$ 0.33	$ 2.36	$ 1.10	$ 1.21	$ 0.32	$ 2.63

Producing Basin	Nine Months Ended September 30, 2016 LOE	Gathering, Compression, Processing and Transportation [a]	Production Taxes	Total	Nine Months Ended September 30, 2015 LOE	Gathering, Compression, Processing and Transportation [a]	Production Taxes	Total
San Juan	$ 1.65	$ 1.11	$ 0.31	$ 3.07	$ 1.31	$ 1.23	$ 0.35	$ 2.89
Piceance	0.31	1.86	0.13	2.30	0.59	2.12	0.22	2.93
Powder River	2.52	—	0.45	2.97	2.14	—	0.65	2.79
Williston	1.22	—	1.02	2.24	0.98	—	0.35	1.33
All other properties	0.37	—	0.12	0.49	1.49	—	0.56	2.05
Total weighted average	$ 1.00	$ 1.18	$ 0.27	$ 2.45	$ 1.14	$ 1.24	$ 0.36	$ 2.74

(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. We did not meet the minimum requirements of this contract until mid-February 2015. 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.

Results of Operations for Oil and Gas for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015: Net loss available for common stock for the Oil and Gas segment was $8.8 million for the three months ended September 30, 2016, compared to Net loss available for common stock of $40 million for the same period in 2015 as a result of:

<u>Revenue</u> decreased primarily due to the decrease in our net commodity hedge position for both crude oil and natural gas, resulting in a 3% decrease in the average hedged price received for crude oil sold, and a 4% decrease in the average hedged price received for natural gas sold. Production increased by 5%. Production was limited in the current period to meet minimum daily quantity contractual gas processing commitments in the Piceance. The increase over the prior year is due to higher processing plant availability when compared to the same period in the prior year.

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

Depreciation, depletion and amortization decreased primarily due to the reduction in our full cost pool resulting from the impact of the ceiling test impairments incurred in the current and prior years, partially offset by the depletion rate applied to greater production.

Impairment of long-lived assets represents non-cash write-downs 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 $12 million in the third quarter of 2016 used an average NYMEX natural gas price of $2.28 per Mcf, adjusted to $1.03 per Mcf at the wellhead, and $41.68 per barrel for crude oil, adjusted to $35.88 per barrel at the wellhead, compared to the $62 million ceiling test write-down in the same period of the prior year which used an average NYMEX natural gas price of $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead, and $59.21 per barrel for crude oil, adjusted to $52.82 per barrel at the wellhead.

Interest income (expense), net increased primarily due to higher interest expense driven by an increase in intercompany notes payable.

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 was comparable for the same period in the prior year.

Results of Operations for Oil and Gas for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015:
Net loss available for common stock for the Oil and Gas segment was $35.3 million for the nine months ended September 30, 2016, compared to Net loss available for common stock of $130 million for the same period in 2015 as a result of:

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 14% decrease in the average hedged price received for crude oil sold, and a 32% decrease in the average hedged price received for natural gas sold. Production was comparable to the same period in the prior year.

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

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

Impairment of long-lived assets represents non-cash write-downs in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices and our decision to divest non-core oil and gas assets. The current write-down of $52 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $38 million. The ceiling test write-down for the nine months ended September 30, 2016 used an average NYMEX natural gas price of $2.28 per Mcf, adjusted to $1.03 per Mcf at the wellhead, and $41.68 per barrel for crude oil, adjusted to $35.88 per barrel at the wellhead, compared to the $178 million ceiling test write-down in the same period of the prior year which used an average NYMEX natural gas price of $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead, and $59.21 per barrel for crude oil, adjusted to $52.82 per barrel at the wellhead.

Interest income (expense), net increased primarily due to higher interest expense driven by an increase in intercompany notes payable.

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

Impairment of equity investments represents a prior year $5.2 million non-cash write-down in equity investments related to interests in a pipeline and gathering system. The impairment resulted from continued declining performance, market conditions and a change in view of the economics of the facilities that we considered to be other than temporary.

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

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015: Net loss available for common stock for Corporate was $7.2 million for the three months ended September 30, 2016, compared to Net loss available for common stock of $5.6 million for the three months ended September 30, 2015. The variance from the prior year was due to higher corporate expenses, primarily driven by higher costs related to the SourceGas acquisition, including approximately $4.0 million of after-tax acquisition and transition costs, compared to $2.8 million of after-tax acquisition and transition costs in the same period of the prior year, and approximately $1.7 million of after-tax internal labor that otherwise would have been charged to other business segments during the three months ended September 30, 2016, compared to $1.2 million after-tax internal labor that otherwise would have been charged to other business segments in the same period of the prior year.

Results of Operations for Corporate activities for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015: Net loss available for common stock for Corporate was $29 million for the nine months ended September 30, 2016, compared to Net loss available for common stock of $7.0 million for the nine months ended September 30, 2015. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition including approximately $24 million of after-tax acquisition and transition costs compared to $3.0 million of after-tax acquisition and transition costs in the same period of the prior year, and approximately $7.4 million of after-tax internal labor that otherwise would have been charged to other business segments during the nine months ended September 30, 2016, compared to $1.8 million of after-tax internal labor that otherwise would have been charged to other business segments in the same period of the prior year. These costs were partially offset by a tax benefit of approximately $4.4 million recognized during the nine months ended September 30, 2016 as a result of an agreement reached with IRS Appeals relating to the release of the reserve for after-tax interest expense previously accrued with respect to the liability for uncertain tax positions involving a like-kind-exchange transaction from 2008.

Critical Accounting Estimates

Except for the additional disclosure below and in Note 1 of Item 1 on this Form 10-Q, there have been no material changes in our critical accounting estimates from those reported in our 2015 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 2015 Annual Report on Form 10-K.

Business Combinations

We record acquisitions in accordance with ASC 805, *Business Combinations*, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, *Business Combinations* requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates.

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.

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.

We also maintain interest rate swap transactions under which we could be required to post collateral on the value of such swaps in the event of an adverse change in our financial condition, including a credit downgrade to below investment-grade.

At September 30, 2016, we had $3.6 million of collateral posted related to our wholesale commodity contracts transactions, and no collateral posted related to our interest rate swaps. At September 30, 2016, 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 nine months ended September 30 (in thousands):

Cash provided by (used in):	2016	2015	Increase (Decrease)
Operating activities	$ 224,677	$ 365,873	$ (141,196)
Investing activities	$ (1,459,196)	$ (356,660)	$ (1,102,536)
Financing activities	$ 840,948	$ 8,410	$ 832,538

Year-to-Date 2016 Compared to Year-to-Date 2015

Operating Activities

Net cash provided by operating activities was $225 million for the nine months ended September 30, 2016, compared to net cash provided by operating activities of $366 million for the same period in 2015 for a variance of $141 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $24 million higher for the nine months ended September 30, 2016 compared to the same period in the prior year;

- Net cash outflows from operating assets and liabilities were $34 million for the nine months ended September 30, 2016, compared to net cash inflows of $98 million in the same period in the prior year. This $132 million variance was primarily due to:

  - Cash inflows decreased by approximately $5.8 million for the nine months ended September 30, 2016 compared to the same period in the prior year primarily as a result of changes in accounts receivable and materials and supplies;

  - Cash inflows decreased by approximately $30 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts on working capital compared to the same period in the prior year;

  - Cash outflows increased by approximately $107 million as a result of changes in accounts payable and accrued liabilities driven primarily by working capital requirements primarily related to acquisition and transition costs and the change in liability with respect to uncertain tax positions for the nine months ended September 30, 2016;

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

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

Investing Activities

Net cash used in investing activities was $1.459 billion for the nine months ended September 30, 2016, compared to net cash used in investing activities of $357 million for the same period in 2015. The variance was primarily driven by:

- Cash outflows of $1.124 billion for the acquisition of SourceGas, net of $11 million cash received from a working capital adjustment and $760 million of long term debt assumed (see Note 2 in Item 1 of Part I of this Quarterly Report on Form 10-Q); and

- Capital expenditures of approximately $334 million for the nine months ended September 30, 2016 compared to $349 million for the nine months ended September 30, 2015. The decrease is primarily due to higher prior year capital expenditures at our Oil and Gas segment due to drilling and completion activity in the Piceance basin, partially offset by higher current year capital expenditures at our Electric and Gas Utilities.

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2016 was $841 million, compared to $8 million of net cash provided by financing activities for the same period in 2015. The variance was primarily driven by:

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP (see Note 11 in Item 1 of Part I of this Quarterly Report on Form 10-Q);

- Long-term borrowings increased by $1.5 billion due to the $693 million of net proceeds from our August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, the $500 million of proceeds from our new term loan on August 9, 2016 used to pay off existing debt, the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition, and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract, compared to proceeds of $300 million from long-term borrowings from a term loan in the prior year;

- Payments on long term borrowings increased by $888 million due to payments made in the current year to refinance the $760 million of long-term debt assumed in the SourceGas Acquisition and $403 million of current year payments made on term loans compared to the payment of $275 million made as part of a term-loan refinancing in the prior year;

- Proceeds of approximately $107 million primarily from issuing common stock under our ATM equity offering program;

- Net short-term borrowings under the revolving credit facility for the nine months ended September 30, 2016 were $45 million lower than the prior year primarily due to using proceeds of our ATM equity offering program to partially fund working capital requirements in the current year;

- Increased dividend payments of approximately $11 million;

- Distributions to noncontrolling interests of $4.5 million; and

- Increased payments for other financings activities of approximately $8.7 million driven primarily by the August 2016 debt refinancings.

Dividends

Dividends paid on our common stock totaled $65 million for the nine months ended September 30, 2016, or $1.26 per share. On October 25, 2016, our board of directors declared a quarterly dividend of $0.42 per share payable December 1, 2016, which is equivalent to an annual dividend rate of $1.68 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 and our corporate Revolving Credit Facility.

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and 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 0.125%, 1.125%, and 1.125%, respectively, at September 30, 2016. A 0.175% commitment fee is charged on the unused amount of the Revolving Credit Facility.

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

Credit Facility	Expiration	Current Capacity	Borrowings at September 30, 2016	Letters of Credit at September 30, 2016	Available Capacity at September 30, 2016
Revolving Credit Facility	August 9, 2021	$ 750	$ 75	$ 31	$ 644

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 and certain guarantees issued by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of September 30, 2016.

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.

Hedges and Derivatives

Interest Rate Swaps

We have entered into pay fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have $75 million notional amount pay fixed interest rate swaps with a maximum remaining term of approximately 0.3 years. These swaps have been designated as cash flow hedges for advances under the Revolving Credit Facility, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $0.7 million at September 30, 2016.

Financing Activities

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046. Proceeds were used to repay the debt assumed in SourceGas Acquisition which included $95 million senior unsecured notes, $325 million senior unsecured notes and the remaining $100 million of the former $340 million term loan. Additionally, the proceeds were used to pay down $100 million on the term loan issued August 9, 2016 discussed below, and for other corporate uses.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan were used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017.

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 included 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.

On June 7, 2016, we entered into a 2.32%, $28.7 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the regulatory asset related to the early termination of a gas supply contract (see Note 2 in Item 1 of Part I of this Quarterly Report on Form 10-Q). Principal and interest are payable quarterly at approximately $1.6 million, the first of which was paid on June 30, 2016.

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for approximately $216 million. FERC approval of the sale was received on March 29, 2016. We used the proceeds from this sale to pay down borrowings on our revolving credit facility. This sale resulted in an increase to stockholders' equity of approximately $62 million as this sale of a portion of the business that is still controlled is accounted for as an equity transaction and no gain or loss on such sale is recorded.

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. During the three months ended September 30, 2016, we issued 819,442 common shares for $49 million, net of $0.5 million in commissions under the ATM equity offering program. Through September 30, 2016, we have sold and issued an aggregate of 1,750,091 shares of common stock under the ATM equity offering program for $106 million, net of $1.1 million in commissions. Additionally, 38,781 shares for net proceeds of $2.4 million have been sold, but were not settled and are not considered issued and outstanding as of September 30, 2016. Proceeds from the ATM equity offering program were used to fund capital expenditures and for general corporate purposes.

We completed the following debt and equity transactions in placing permanent financing for the SourceGas Acquisition:

- On January 13, 2016, we completed a public debt offering of $550 million in senior unsecured notes. The debt offering consisted of $300 million of 3.95%, 10-year senior notes due 2026, and $250 million of 2.5%, 3-year senior notes due 2019. Net proceeds after discounts and fees were approximately $546 million; and

- On November 23, 2015, we completed offerings of common stock and equity units. We issued 6.325 million shares of common stock for net proceeds of $246 million and 5.98 million equity units for net proceeds of $290 million. Each equity unit has a stated amount of $50 and consists of (i) a contract to purchase Company common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of remarketable junior subordinated notes due 2028. Pursuant to the purchase contracts, holders are required to purchase Company common stock no later than November 1, 2018.

Our $1.17 billion bridge commitment signed on July 12, 2015 was reduced to $88 million on January 13, 2016, with respect to reductions from our equity and debt offerings. The remaining commitment terminated on February 12, 2016, as part of the closing of the SourceGas Acquisition.

We assumed the following tranches of debt through the SourceGas Acquisition on February 12, 2016; all of which were refinanced in August of 2016 as outlined above:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 16, 2017.

- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.

- $340 million unsecured corporate term-loan due June 30, 2017. Interest expense under this term loan was LIBOR plus a margin of 0.88%.

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

Future Financing Plans

We anticipate the following financing activities:

- Continuing our ATM equity offering program; and
- Implementing a commercial paper program.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of September 30, 2016, 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 0.70 to 1.00 at the end of the fiscal quarters ending in September 30, 2016 and December 31, 2016 and not to exceed 0.65 to 1.00 at the end of any fiscal quarter thereafter. Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of September 30, 2016, 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 2015 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

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

The following table represents the credit ratings and outlook and risk profile of BHC at September 30, 2016:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB	Stable
Moody's [(b)]	Baa1	Negative
Fitch [(c)]	BBB+	Negative

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(a) On February 12, 2016, S&P affirmed 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 February 12, 2016, Moody's affirmed Baa1 rating and maintained a Negative outlook following the closing of the SourceGas Acquisition. Moody's has maintained a negative outlook as BHC focuses on integrating the newly acquired SourceGas assets over 12 months following the acquisition, closing the 49.9% minority interest sale of Colorado IPP and implementing and utilizing an at-the-market (ATM) equity offering program. In addition, the negative outlook reflects overall weaker consolidated metrics when compared to historical ranges.
(c) On February 12, 2016, Fitch affirmed BBB+ rating and maintained a Negative outlook following the closing of the SourceGas Acquisition, which reflects the initial increased leverage associated with the SourceGas acquisition.

The following table represents the credit ratings of Black Hills Power at September 30, 2016:

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

Acquisition of SourceGas

The acquisition of SourceGas was primarily financed with net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.3 million shares of our common stock and 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 12, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

Capital Expenditures

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

	Expenditures for the Nine Months Ended September 30, 2016 [(a)]	Total 2016 Planned Expenditures [(b)(c)]	Total 2017 Planned Expenditures	Total 2018 Planned Expenditures
Electric Utilities [(c)]	$ 210,068	$ 278,000	$ 138,300	$ 108,400
Gas Utilities	109,171	170,400	165,700	162,700
Power Generation	3,874	5,800	1,800	6,900
Mining	1,742	6,000	6,600	6,600
Oil and Gas	2,943	7,600	3,300	11,100
Corporate	10,032	12,300	8,300	9,000
	$ 337,830	$ 480,100	$ 324,000	$ 304,700

(a) Expenditures for the nine months ended September 30, 2016 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the nine months ended September 30, 2016.
(c) 2016 forecasted capital expenditures for the electric utilities include approximately $97 million for the Peak View Wind Project and the remaining $29 million for Colorado Electric's 40 MW natural gas fired generating unit.

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

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at September 30, 2016. The table below has been updated to reflect the additional long-term debt and other commitments and contractual obligations assumed through the acquisition of SourceGas, as well as the agreement in principle reached with IRS Appeals relating to the re-measurement of uncertain tax positions relating to the 2008 IPP Transaction and the Aquila Transaction. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Calendar Period				
Contractual Obligations	Total	2016	2017-2018	2019-2020	Thereafter
Long-term debt[(a)(b)]	$ 3,244,697	$ 1,436	$ 11,486	$ 861,485	$ 2,370,290
Unconditional purchase obligations[(c)]	749,130	39,856	268,529	160,445	280,300
Operating lease obligations[(d)]	26,495	1,485	9,225	6,249	9,536
Other long-term obligations[(e)]	69,540	—	—	—	69,540
Employee benefit plans[(f)]	161,054	15,859	48,050	32,132	65,013
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	31,986	26,285	5,701	—	—
Notes payable	75,000	75,000	—	—	—
Total contractual cash obligations[(h)]	$ 4,357,902	$ 159,921	$ 342,991	$ 1,060,311	$ 2,794,679

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

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period and are not included within the long-term debt balances presented: $28 million in 2016, $124 million in 2017, $122 million in 2018, $108 million in 2019 and $101 million in 2020. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of September 30, 2016.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charge under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2016 and price assumptions using existing prices at September 30, 2016. Our transmission obligations are based on filed tariffs as of December 31, 2015. The gathering commitments for our Oil and Gas segment are described in Part I, Delivery Commitments, of our 2015 Annual Report filed on Form 10-K.

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

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities, Mining and Oil and Gas segments as discussed in Note 8 on this Form 10-Q and Note 8 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2024.

(g) Less than 1 Year includes a reversal of approximately $26 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction. Such reversal is the result of an agreement that was reached with IRS Appeals during the first quarter of 2016. See Note 21 for additional details.

(h) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at September 30, 2016. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Our Utilities have commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. As of September 30, 2016, we are committed to purchase 5.5 Bcf, 24.2 Bcf, 1.2 Bcf and 0.7 Bcf in 2016, 2017, 2018, and 2019, respectively.

Guarantees

Other than those disclosed in Note 19 of the Notes to the Condensed Consolidated Financial Statements on Form 10-Q, 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 2015 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2015 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 2015 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2015 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

	September 30, 2016	December 31, 2015	September 30, 2015
Net derivative (liabilities) assets	$ (10,800)	$ (22,292)	$ (21,322)
Cash collateral offset in Derivatives	11,584	22,292	21,322
Cash collateral included in Other current assets	4,602	5,367	2,631
Net asset (liability) position	$ 5,386	$ 5,367	$ 2,631

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2016 and 2017 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at September 30, 2016, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2016					
Swaps - MMBtu	—	—	—	545,000	545,000
Weighted Average Price per MMBtu	$ —	$ —	$ —	$ 3.90	$ 3.90
2017					
Swaps - MMBtu	270,000	270,000	270,000	270,000	1,080,000
Weighted Average Price per MMBtu	$ 2.88	$ 2.88	$ 2.88	$ 2.88	$ 2.88

Crude Oil

	March 31	June 30	September 30	December 31	Total Year
2016					
Swaps - Bbls	—	—	—	51,000	51,000
Weighted Average Price per Bbl	$ —	$ —	$ —	$ 73.14	$ 73.14
2017					
Swaps - Bbls	18,000	18,000	18,000	18,000	72,000
Weighted Average Price per Bbl	$ 50.07	$ 50.85	$ 51.55	$ 52.33	$ 51.20
Calls - Bbls	9,000	9,000	9,000	9,000	36,000
Weighted Average Price per Bbl	$ 50.00	$ 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:

	September 30, 2016	December 31, 2015	September 30, 2015
Net derivative (liabilities) assets	$ 2,177	$ 10,088	$ 10,797
Cash collateral offset in Derivatives	—	(10,088)	(10,797)
Cash Collateral included in Other current assets	—	1,673	3,556
Net asset (liability) position	$ 2,177	$ 1,673	$ 3,556

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. 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 2015 Annual Report on Form 10-K and in Note 13 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

	September 30, 2016	December 31, 2015		September 30, 2015
	Designated Interest Rate Swaps (b)	Designated Interest Rate Swaps (a)	Designated Interest Rate Swaps (b)	Designated Interest Rate Swaps (b)
Notional	$ 75,000	$ 250,000	$ 75,000	$ 75,000
Weighted average fixed interest rate	4.97%	2.29%	4.97%	4.97%
Maximum terms in years	0.33	1.33	1.00	1.33
Derivative assets, non-current	$ —	$ 3,441	$ —	$ —
Derivative liabilities, current	$ 654	$ —	$ 2,835	$ 3,312
Derivative liabilities, non-current	$ —	$ —	$ 156	$ 722
Pre-tax accumulated other comprehensive income (loss)	$ (654)	$ 3,441	$ (2,991)	$ (4,034)

____

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

(b) These swaps are designated to borrowings on our Revolving Credit Facility and are priced using three-month LIBOR, matching the floating portion of the related borrowings.

Based on September 30, 2016 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.4 million 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 interest rates change.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of September 30, 2016. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at September 30, 2016.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission’s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2016, 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.

On February 12, 2016, our acquisition of SourceGas closed. We are currently in the process of integrating and aligning the operations, processes, and internal controls of the combined company. See Note 2 for more information regarding the acquisition. As permitted by the guidance set forth by the Securities and Exchange Commission, the acquired businesses will not be included in management’s assessment of internal control over financial reporting for the year ending December 31, 2016.

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2015 Annual Report on Form 10-K and Note 19 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 19 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Other than as set forth below, there are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2015 Annual Report on Form 10-K filed with the SEC.

Oil and Gas

Our inability to successfully include our Oil and Gas segment core assets in utility Cost of Service Gas Programs may result in additional material impairments of our Oil and Gas assets.

In our oil and gas business, we are divesting non-core assets while retaining those best suited for a Cost of Service Gas Program for our utilities and third-party utilities, and have refocused our professional staff on assisting with the implementation of a Cost of Service Gas Program. The implementation of Cost of Service Gas Programs provides a long-term physical hedge for a portion of a utility's gas supply, enhancing the gas supply portfolio and providing longer-term price stability for regulated utility customers. In addition to providing customers the benefits associated with more predictable long-term natural gas prices, it also provides utilities an opportunity to increase earnings through the investment in gas reserves. Cost of Service Gas Programs require regulatory approval from state commissions that regulate utility participants in these programs. Failure to obtain these approvals would likely result in additional material impairments of our Oil and Gas assets, and could adversely affect the market perception of our business, operating results and stock price.

Risks Related to the SourceGas Acquisition

We recorded goodwill that could become impaired and adversely affect our financial condition and results of operations.

The acquisition of SourceGas was accounted for as a purchase in accordance with GAAP. Under the purchase method of accounting, the assets and liabilities acquired and assumed were recorded at their fair values at the date of acquisition and added to those of Black Hills Corporation. The excess of the purchase price over the estimated fair values was recorded as goodwill. As of September 30, 2016, goodwill totaled $1.3 billion, of which $941 million is attributable to the acquisition of SourceGas.

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

Failure to maintain effective internal controls over financial reporting could have a negative effect on our business, operating results and stock price.

Prior to the Acquisition, SourceGas was a private company, exempt from reporting and control requirements under Section 404 of the Sarbanes-Oxley Act of 2002. Section 404 of the Sarbanes-Oxley Act of 2002 requires us to include in our annual report a report containing management's assessment of the effectiveness of our internal controls over financial reporting as of the end of our fiscal year and a statement as to whether or not such internal controls are effective. As permitted by the guidance set forth by the Securities and Exchange Commission, the acquired SourceGas businesses will not be included in management's assessment of internal control over financial reporting for the year ended December 31, 2016.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. While we expect our control system to adequately integrate the SourceGas processes, we cannot be certain that our current design for internal control over financial reporting, or any additional changes to be made, will be sufficient to enable management to determine that our internal controls are effective for any period, or on an ongoing basis. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

Financing

Failure to maintain our financial and other covenants required by our credit facility agreement and term loan could have a negative effect on our business, operating results and stock price.

On February 12, 2016, in connection with the SourceGas Acquisition, our Revolving Credit Facility and Term Loan credit agreements were amended to permit the assumption of certain indebtedness of SourceGas and to increase the Recourse Leverage Ratio. The maximum Recourse Leverage Ratio increased to 0.75 to 1.00 until March 31, 2017, a period of four fiscal quarters following the SourceGas acquisition; it was previously 0.65 to 1.00. On August 9, 2016, in conjunction with the amendment and restatement of the Revolving Credit Facility and Term Loan, the Recourse Leverage Ratio was amended and replaced with the Consolidated Indebtedness to Capitalization Ratio. Under the amended and restated Revolving Credit Facility and Term Loan, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00 at the end of fiscal quarters ending September 30, 2016 and December 31, 2016 and not to exceed 0.65 to 1.00 at the end of any fiscal quarter thereafter. We were in compliance at September 30, 2016, with a Consolidated Indebtedness to Capitalization Ratio of 68%. If we are not able to meet the compliance ratio of 65% at March 31, 2017, and are not able to obtain a waiver of non-compliance, failure to comply with this covenant could result in default, and could cause all outstanding borrowings under our credit facility agreement and term loan to become immediately due and payable, which could have a material and adverse effect on our business.

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

There were no unregistered securities sold during the nine months ended September 30, 2016.

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 January 28, 2010 (filed as Exhibit 3 to the Registrant’s Form 8-K filed on February 3, 2010).
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).
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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 10.1*	Second Amended and Restated Senior Credit Agreement dated August 9, 2016, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on August 10, 2016).
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Exhibit 10.4†	Fourth Amendment to the Outside Director Stock Based Compensation Plan effective 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: November 3, 2016

INDEX TO EXHIBITS

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

FOURTH AMENDMENT TO THE AMENDED AND RESTATED OUTSIDE DIRECTORS STOCK BASED COMPENSATION PLAN

This Fourth Amendment to the Amended and Restated Outside Directors Stock Based Compensation Plan (“Amendment”) is adopted by Black Hills Corporation (“Company”) effective the 1st day of January, 2017.

1. RECITALS.

This document is the Fourth Amendment to the Amended and Restated Outside Directors Stock Based Compensation Plan which was adopted by the Company effective the 1st day of January, 2017 (“Plan”). Under Section 11 of the Plan, the Company reserved the right to amend, modify, or discontinue the Plan provided only that any modification is not to reduce accrued and unpaid benefits. The amendment hereunder does not reduce any accrued or unpaid benefits.

2. AMENDMENTS TO SECTION 4. ADDITIONS TO ACCOUNTS.

Section 4b of the Plan is amended and restated as follows:

b. For the Quarter Period December 1, 2007 through February 29, 2008, each Participant shall be entitled to a quarterly addition to their Account in the amount determined by dividing the sum of $11,333.33 by the market price of the Company common stock on February 29, 2008.

   For the Quarter Period beginning March 1, 2008, and for the remainder of the Plan year, and for each Plan year thereafter through November 30, 2010 each Participant shall be entitled to a quarterly addition to his or her Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $12,500 by the market price of the Company common stock on the last day of the Quarter Period for each Quarter Period of the Plan Year that the Participant is eligible for benefits.

For the Quarter Period December 1, 2010 through February 28, 2011, each Participant shall be entitled to a quarterly addition to their Account in the amount determined by dividing the sum of $14,166.67 by the market price of the Company common stock on February 28, 2011.

For the Quarter Period beginning March 1, 2011, and for the remainder of the Plan year, and for each Plan year thereafter through November 30, 2012 each Participant shall be entitled to a quarterly addition to his or her Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $15,000 by the market price of the Company common stock on the last day of the Quarter Period for each Quarter Period of the Plan Year that the Participant is eligible for benefits.

For the Quarter Period December 1, 2012 through February 28, 2013, each Participant shall be entitled to a quarterly addition to their Account in the amount determined by dividing the sum of $17,500.00 by the market price of the Company common stock on February 28, 2013.

For the Quarter Period beginning March 1, 2013, and for the remainder of the Plan year, and for each Plan year thereafter through November 30, 2014, each Participant shall be entitled to a quarterly addition to his or her Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $18,750 by the market price of the Company common stock on the last day of the Quarter Period for each Quarter Period of the Plan Year that the Participant is eligible for benefits.

For the Quarter Period December 1, 2014 through February 28, 2015, each Participant shall be entitled to a quarterly addition to their Account in the amount determined by dividing the sum of $19,583.33 by the market price of the Company common stock on February 28, 2015.

For the Quarter Period beginning March 1, 2015, and for the remainder of the Plan year, and for each Plan year thereafter through November 30, 2016, each Participant shall be entitled to a quarterly addition to his or her Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $20,000 by the market price of the Company common stock on the last day of the Quarter Period for each Quarter Period of the Plan Year that the Participant is eligible for benefits.

For the Quarter Period December 1, 2016 through February 28, 2017, each Participant shall be entitled to a quarterly addition to their Account in the amount determined by dividing the sum of $21,666.67 by the market price of the Company common stock on February 28, 2017.

For the Quarter Period beginning March 1, 2017, and for the remainder of the Plan year, and for each Plan year thereafter, each Participant shall be entitled to a quarterly addition to his or her Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $22,500 by the market price of the Company common stock on the last day of the Quarter Period for each Quarter Period of the Plan Year that the Participant is eligible for benefits.

If a Participant is not an Outside Director for the entire Quarter Period, then the Participant's addition for the quarter should be prorated for the number of months that the Participant served as Outside Director.

3. NO OTHER CHANGES.

Other than specifically set forth herein, all terms, conditions and provisions of the Plan shall remain the same.

Dated this 24th day of October, 2016.

BLACK HILLS CORPORATION

By /s/ David R. Emery
Its Chairman and CEO

ATTEST:

/s/ Roxann R. Basham
Secretary

(CORPORATE SEAL)

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: November 3, 2016

/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: November 3, 2016

/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 September 30, 2016 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: November 3, 2016

/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 September 30, 2016 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: November 3, 2016

/S/ RICHARD W. KINZLEY

Richard W. Kinzley
Senior Vice President and Chief Financial Officer

Exhibit 95

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 September 30, 2016. 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 September 30, 2016 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 September 30, 2016	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	—	—	—	—	—	$ —	—	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.