BLACK HILLS CORP /SD/
Form 10-Q
May 10, 2016

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 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 April 30, 2016	
Common stock, $1.00 par value	51,587,415	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
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 all of 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 all Black Hills Power operations in South Dakota, Wyoming and Montana
Black Hills Energy Wyoming Electric	Includes all of 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

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 (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-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	A program our utility subsidiaries submitted applications for with respective state utility regulators in Iowa, Kansas, Nebraska, South Dakota, Colorado and Wyoming, seeking approval for a 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
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
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)
Energy West	Energy West Wyoming, Inc., a subsidiary of Gas Natural, Inc. Energy West is an acquisition we closed on July 1, 2015 (doing business as Black Hills Energy)
EPA	United States Environmental Protection Agency
Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RNSs due 2028.
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Global Settlement	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders.
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 (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent power producer
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
KCC	Kansas Corporation Commission
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent.

MGTC	MGTC, Inc., a gas utility in northeast Wyoming serving 400 customers. MGTC is an acquisition we closed on January 1, 2015 (doing business as Black Hills Energy)

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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 (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOL	Net Operating Loss
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Peak View Wind Project	New $109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm
PPA	Power Purchase Agreement
Recourse Leverage Ratio	Any indebtedness outstanding at such time, divided by Capital at such time. Capital being consolidated net-worth plus all recourse indebtedness.
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2020.
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)
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	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.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended March 31,	
	2016	2015
	(in thousands, except per share amounts)	
Revenue	$449,959	$441,987
Operating expenses:		
Fuel, purchased power and cost of natural gas sold	171,856	205,327
Operations and maintenance	107,062	93,134
Depreciation, depletion and amortization	44,407	39,002
Taxes - property, production and severance	12,117	11,936
Impairment of long-lived assets	14,496	22,036
Other operating expenses	26,431	52
Total operating expenses	376,369	371,487
Operating income (loss)	73,590	70,500
Other income (expense):		
Interest charges -		
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(32,074)	(19,910)
Allowance for funds used during construction - borrowed	501	158
Capitalized interest	235	276
Interest income	655	448
Allowance for funds used during construction - equity	707	56
Other income (expense), net	688	331
Total other income (expense), net	(29,288)	(18,641)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	44,302	51,859
Equity in earnings (loss) of unconsolidated subsidiaries	—	(297)
Income tax benefit (expense)	(4,252)	(17,712)
Net income (loss)	40,050	33,850
Net income attributable to non-controlling interest	(48)	—
Net income (loss) available for common stock	$40,002	$33,850
Earnings (loss) per share of common stock:		
Earnings (loss) per share, Basic	$0.78	$0.76
Earnings (loss) per share, Diluted	$0.77	$0.76
Weighted average common shares outstanding:		
Basic	51,044	44,541
Diluted	51,858	44,660
Dividends declared per share of common stock	$0.420	$0.405

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 March 31,	
	2016	2015
	(in thousands)	
Net income (loss)	$40,050	$33,850
Other comprehensive income (loss), net of tax:		
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $4,576 and $(1,042) for the three months ended 2016 and 2015, respectively)	(8,644)	1,836
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $1,946 and $1,254 for the three months ended 2016 and 2015, respectively)	(3,412)	(1,241)
Benefit plan liability adjustments - net gain (loss) (net of tax (expense) benefit of $0 and $15 for the three 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, respectively)	(36)	(36)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(172) and $(247) for the three months ended 2016 and 2015, respectively)	322	458
Other comprehensive income (loss), net of tax	(11,770)	990
Comprehensive income (loss)	28,280	34,840
Less: comprehensive income attributable to non-controlling interest	(48)	—
Comprehensive income (loss) available for common stock	$28,232	$34,840

See Note 15 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of		
	March 31, 2016	December 31, 2015	March 31, 2015
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$46,974	$456,535	$63,385
Restricted cash and equivalents	1,839	1,697	2,191
Accounts receivable, net	206,276	147,486	178,421
Materials, supplies and fuel	78,176	86,943	66,626
Derivative assets, current	1,486	—	—
Income tax receivable, net	—	368	159
Deferred income tax assets, net, current	—	—	23,913
Regulatory assets, current	54,108	57,359	56,542
Other current assets	34,287	71,763	47,448
Total current assets	423,146	822,151	438,685
Investments	12,126	11,985	17,210
Property, plant and equipment	6,063,943	4,976,778	4,652,058
Less: accumulated depreciation and depletion	(1,742,070)	(1,717,684)	(1,407,214)
Total property, plant and equipment, net	4,321,873	3,259,094	3,244,844
Other assets:			
Goodwill	1,306,169	359,759	353,396
Intangible assets, net	10,957	3,380	3,121
Regulatory assets, non-current	239,023	175,125	178,935
Derivative assets, non-current	85	3,441	—
Other assets, non-current	11,274	7,382	16,994
Total other assets, non-current	1,567,508	549,087	552,446
TOTAL ASSETS	$6,324,653	$4,642,317	$4,253,185

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

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

	As of March 31, 2016	December 31, 2015	March 31, 2015
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$121,684	$105,468	$88,770
Accrued liabilities	272,181	232,061	166,781
Derivative liabilities, current	3,965	2,835	3,342
Accrued income taxes, net	10,899	—	—
Regulatory liabilities, current	35,933	4,865	17,621
Notes payable	215,600	76,800	102,600
Total current liabilities	660,262	422,029	379,114
Long-term debt	3,159,055	1,853,682	1,531,372
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	500,202	450,579	503,117
Derivative liabilities, non-current	14,522	156	2,143
Regulatory liabilities, non-current	200,337	148,176	148,918
Benefit plan liabilities	181,270	146,459	162,334
Other deferred credits and other liabilities	124,181	155,369	154,604
Total deferred credits and other liabilities	1,020,512	900,739	971,116
Commitments and contingencies (See Notes 9, 10, 17, 18)			
Redeemable non-controlling interest	4,141	—	—
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 51,477,472; 51,231,861; and 44,856,790 shares, respectively	51,477	51,232	44,857
Additional paid-in capital	960,605	953,044	749,517
Retained earnings	490,999	472,534	592,951
Treasury stock, at cost – 30,903; 39,720; and 33,755 shares, respectively	(1,573)	(1,888)	(1,688)
Accumulated other comprehensive income (loss)	(20,825)	(9,055)	(14,054)
Total stockholders' equity	1,480,683	1,465,867	1,371,583
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$6,324,653	$4,642,317	$4,253,185

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Three Months Ended March 31,	
	2016	2015
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$40,002	$33,850
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	44,407	39,002
Deferred financing cost amortization	1,666	519
Impairment of long-lived assets	14,496	22,036
Stock compensation	4,461	2,083
Deferred income taxes	32,579	14,640
Employee benefit plans	3,466	5,283
Other adjustments, net	(5,000)	6,748
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	25,822	25,689
Accounts receivable, unbilled revenues and other operating assets	27,559	13,954
Accounts payable and other operating liabilities	(68,101)	(44,652)
Regulatory assets - current	12,856	20,272
Regulatory liabilities - current	11,613	13,721
Other operating activities, net	(7,489)	(1,658)
Net cash provided by (used in) operating activities	138,337	151,487
Investing activities:		
Property, plant and equipment additions	(83,885)	(117,523)
Acquisition, net of long term debt assumed and cash acquired	(1,132,318)	—
Other investing activities	(329)	(348)
Net cash provided by (used in) investing activities	(1,216,532)	(117,871)
Financing activities:		
Dividends paid on common stock	(21,537)	(18,148)
Common stock issued	7,821	999
Short-term borrowings - issuances	208,100	77,700
Short-term borrowings - repayments	(69,300)	(50,100)
Long-term debt - issuances	545,959	—
Other financing activities	(2,409)	(1,900)
Net cash provided by (used in) financing activities	668,634	8,551
Net change in cash and cash equivalents	(409,561)	42,167
Cash and cash equivalents, beginning of period	456,535	21,218
Cash and cash equivalents, end of period	$46,974	$63,385

See Note 16 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 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 utilities, other than the Oil and Gas segment, and in 2015 we began transitioning the Oil and Gas business to support utilities through a Cost of Service Gas Program. The following changes have been made to our Condensed Consolidated Statements of Income to reflect combined operations and maintenance expenses, rather than by business group as previously reported, for the three months ended March 31, 2015:

	For the Three Months Ended March 31, 2015		
(in thousands)	As Previously Reported	Presentation Reclassification	As Currently Reported
Utilities - operations and maintenance	$71,084	$ (71,084)	$ —
Non-regulated energy operations and maintenance	$22,050	$ (22,050)	$ —
Operations and maintenance	$—	$ 93,134	$ 93,134

This presentation reclassification did not impact our 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 period ending March 31, 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 March 31, 2016, December 31, 2015, and March 31, 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 months ended March 31, 2016 and March 31, 2015, and our financial condition as of March 31, 2016, December 31, 2015, and March 31, 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

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. Our significant assumptions and estimates can include, but are not limited to, the cash flows that an acquired entity is expected to generate in the future, the appropriate weighted-average cost of capital, and the savings expected to be derived from the business combination. 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.

Recently Issued and Adopted Accounting Standards

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

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact that adoption of ASU 2016-09 will have on its consolidated financial position, results of operations, cash flows, and disclosure.

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, 2019. Early adoption is permitted. We are currently assessing the impact that adoption of ASU 2016-02 will have on our financial position, results of operations or cash flows.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, 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 would be effective for annual and interim reporting periods beginning after December 15, 2017 and early adoption is permitted. We are currently assessing the impact that adoption of ASU 2014-09 will have on our financial position, results of operations or 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 will be 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 March 31, 2016, we have 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 $11 million in the Condensed Consolidated Balance Sheets as of December 31 2015 and March 31, 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 March 31, 2016. Adoption of this standard did not have a material impact on the Company’s financial position, results of operations or cash flows.

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(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 is subject to post-closing adjustments for capital expenditures, indebtedness and working capital, which will be determined and agreed to, subject to a review period. 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, we recorded pre-tax acquisition costs of approximately $25 million in the three months ended March 31, 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. No acquisition costs were recorded in the three months ended March 31, 2015.

Our consolidated operating results for the three months ended March 31, 2016 include revenues of $76 million and net income of $7.6 million attributable to SourceGas for the period from February 12 through March 31, 2016. SourceGas is included in our Gas Utilities reporting 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 $1.132 billion, net of long-term debt assumed of $760 million and cash acquired of $2.5 million, resulted in a preliminary estimate of goodwill totaling $946 million. These estimates are 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. Approximately $219 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.

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	(in thousands)
Preliminary Purchase Price	$1,894,882
Less: Long-term debt assumed	(760,000)
Consideration Paid	$1,134,882
Preliminary Allocation of Purchase Price:	
Current Assets	$119,549
Property, plant & equipment, net	1,015,200
Goodwill	946,410
Deferred charges and other assets, excluding goodwill	136,240
Current liabilities	(172,710)
Long-term debt	(760,000)
Deferred credits and other liabilities	(149,807)
Total preliminary consideration paid	$1,134,882

Conditions of 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 are 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.

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 months ended March 31, 2016 and March 31, 2015. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2015:

	Pro Forma Results For the Three Months Ended	
	March 31, 2016	March 31, 2015
	(in thousands, except per share amounts)	
Revenue	$528,921	$628,464
Net income (loss) available for common stock	$66,690	$52,041
Earnings (loss) per share, Basic	$1.31	$1.02
Earnings (loss) per share, Diluted	$1.29	$1.01

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 months ended March 31, 2015, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2015, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the Acquisition, and exclude any unique one-time items that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the three months ended March 31, 2016 reflect lower gas pricing than in 2015 and tax benefits realized in the first quarter of 2016, as described in Footnote 20. 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 non-controlling 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 is provided a put option to sell us the retained interest.

(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 March 31, 2016	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Segment:			
Electric	$163,531	$ 3,745	$19,215
Gas	268,667	1,806	31,975
Power Generation	1,852	21,456	8,582
Mining	7,534	8,748	2,938
Oil and Gas [a]	8,375	—	(7,024)
Corporate activities [b][d]	—	—	(15,684)
Inter-company eliminations	—	(35,755)	—
Total	$449,959	$ —	$40,002

Three Months Ended March 31, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Segment:			
Electric [c]	$166,493	$ 3,424	$17,553
Gas [c]	254,132	—	23,588
Power Generation	1,953	20,721	8,145
Mining	8,142	7,792	3,010
Oil and Gas [a]	11,267	—	(19,115)
Corporate activities	—	—	669
Inter-company eliminations	—	(31,937)	—
Total	$441,987	$ —	$33,850

(a) Net income (loss) for the three months ended March 31, 2016 and March 31, 2015 include non-cash after-tax ceiling test impairments of $8.8 million and $14 million, respectively. See Note 19 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) for the three months ended March 31, 2016 included incremental, non-recurring acquisition costs, net of tax of $15 million and after-tax internal labor costs attributable to the acquisition of $3.8 million. See Note 2 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) 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 months ended March 31, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Revenue and Net Income of $16 million and $1.4 million, respectively, previously reported in the Electric Utility segment in 2015 are now included in the Gas Utility segment.

(d) Includes net income attributable to non-controlling interest of $0.1 million.

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

Total Assets (net of inter-company eliminations) as of:	March 31, 2016	December 31, 2015	March 31, 2015
Segment:			
Electric [(a)] [(b)]	$2,714,450	$2,720,004	$2,691,822
Gas [(b)]	3,146,315	999,778	960,435
Power Generation [(a)]	74,403	60,864	75,945
Mining	73,878	76,357	77,399
Oil and Gas [(c)]	197,291	208,956	348,300
Corporate activities [(d)]	118,316	576,358	99,284
Total assets	$6,324,653	$4,642,317	$4,253,185

(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 three months ended March 31, 2015 have been reclassified from the Electric Utility segment to the Gas Utility segment. Assets of $135 million and $121 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 March 31, 2015.

(c) As a result of continued low commodity prices during 2016 and 2015, we recorded non-cash impairments of oil and gas assets included in our Oil and Gas segment of $14 million for the for the three months ended March 31, 2016, $250 million for the year ended December 31, 2015, and $22 million for the three months ended March 31, 2015. See Note 19 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.

(4) ACCOUNTS RECEIVABLE

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

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

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

March 31, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities [(a)]	$ 49,046	$ 23,088	$ (873)	$ 71,261
Gas Utilities [(a)]	68,068	30,237	(1,549)	96,756
Power Generation	1,152	—	—	1,152
Mining	3,638	—	—	3,638
Oil and Gas	4,646	—	(13)	4,633
Corporate	981	—	—	981
Total	$ 127,531	$ 53,325	$ (2,435)	$ 178,421

(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 $6.3 million as of December 31, 2015 and March 31, 2015, respectively, previously reported in the Electric Utility segment is now presented in the Gas Utility segment.

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(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of March 31, 2016	As of December 31, 2015	As of March 31, 2015
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)] [(d)]	1	$24,479	$24,751	$30,833
Deferred gas cost adjustments [(a)(d)]	1	14,895	15,521	6,138
Gas price derivatives [(a)]	7	20,324	23,583	21,606
AFUDC [(b)]	45	13,677	12,870	12,114
Employee benefit plans [(c)] [(e)]	12	111,661	83,986	97,700
Environmental [(a)]	subject to approval	1,162	1,180	1,240
Asset retirement obligations [(a)]	44	487	457	3,237
Bond issue cost [(a)]	22	3,097	3,133	3,240
Renewable energy standard adjustment [(b)]	5	4,507	5,068	5,590
Flow through accounting [(c)]	35	30,614	29,722	26,835
Decommissioning costs [(f)]	10	18,134	18,310	13,702
Gas supply contract termination	5	30,613	—	—
Other regulatory assets [(a)]	15	19,481	13,903	13,242
		$293,131	$232,484	$235,477
Regulatory liabilities				
Deferred energy and gas costs [(a)] [(d)]	1	$40,797	$7,814	$18,094
Employee benefit plans [(c)] [(e)]	12	63,580	47,218	53,151
Cost of removal [(a)]	44	123,076	90,045	81,449
Other regulatory liabilities [(c)]	25	8,817	7,964	13,845
		$236,270	$153,041	$166,539

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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, respectively.

(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 $13 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.

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 vary, currently ranging from $6 to $8 per MMBtu, and exceed market prices. We recorded a liability for this contract in our purchase price allocation. We applied for and subsequent to March 31, 2016, we were granted approval to terminate these agreements with 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 settled the liability on April 29, 2016. See Note 22.

(6) MATERIALS, SUPPLIES AND FUEL

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

	March 31, 2016	December 31, 2015	March 31, 2015
Materials and supplies	$66,542	$ 55,726	$52,429
Fuel - Electric Utilities	5,365	5,567	6,780
Natural gas in storage held for distribution	6,269	25,650	7,417
Total materials, supplies and fuel	$78,176	$ 86,943	$66,626

(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	$250,487	$100,507	$ 8,765	$359,759
Acquisition of SourceGas (a)	—	946,410	—	946,410
Ending balance at March 31, 2016	$250,487	$1,046,917	$ 8,765	$1,306,169

(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 December 31, 2015	$3,380
Additions, net (a)	7,734
Amortization expense	(157)
Intangible assets, net, ending balance at March 31, 2016	$10,957

(a) Intangible assets, net acquired from SourceGas are primarily trademarks and tradenames, and are amortized over 5-year estimated useful lives. See Note 2 for more information.

(8) 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 March 31,	
2016	2015

Net income (loss) available for common stock	$40,002	$33,850
Weighted average shares - basic	51,044	44,541
Dilutive effect of:		
Equity Units [(a)]	720	—
Equity compensation	94	119
Weighted average shares - diluted	51,858	44,660

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(a) Calculated using the treasury stock method.

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

	Three Months Ended March 31,	
	2016	2015
Equity compensation	74	107
Anti-dilutive shares	74	107

(9) NOTES PAYABLE

We had the following short-term debt outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	March 31, 2016		December 31, 2015		March 31, 2015	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$215,600	$24,000	$76,800	$33,399	$102,600	$22,300

Revolving Credit Facility

On June 26, 2015, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through June 26, 2020. 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 the capacity of the facility to $750 million. 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 and/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 March 31, 2016. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating.

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, and we 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 for the next four fiscal quarters; it was previously 0.65 to 1.00. Additionally, covenants within Black Hills Gas Holdings financing agreements require Black Hills Gas Holdings to maintain a consolidated debt to capitalization ratio of no more than 0.75 to 1.00.

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

As of March 31, 2016

		Covenant Requirement
Recourse Leverage Ratio	71%	Less than 75%

As of March 31, 2016, we were in compliance with this covenant.

(10) LONG-TERM DEBT

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

	Interest Rate at March 31, 2016	March 31, 2016	December 31, 2015	March 31, 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		(892)	—	—
Senior unsecured notes due November 30, 2023	4.25%	525,000	525,000	525,000
Unamortized discount on Senior unsecured notes due 2023		(1,822)	(1,890)	(2,095)
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		(282)	—	—
Corporate term loan due June 30, 2017 (a) (b)	1.38%	340,000	—	—
Corporate term loan due April 12, 2017 (b)	1.40%	300,000	300,000	—
Corporate term loan due June 19, 2015 (b)	1.31%	—	—	275,000
Total Corporate Debt		2,211,004	1,322,110	997,905
Gas Utilities				
Senior secured notes due September 29, 2019 (a) (e)	3.98%	95,000	—	—
Senior unsecured notes due April 1, 2017 (a)	5.90%	325,000	—	—
Unamortized discount on Senior unsecured notes due 2017		(103)	—	—
		419,897	—	—
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		(97)	(99)	(102)
First Mortgage Bonds due November 20, 2037	6.67%	110,000	110,000	110,000
Industrial development revenue bonds due September 1, 2021 (c)	0.45%	7,000	7,000	7,000
Industrial development revenue bonds due March 1, 2027 (c)	0.47%	10,000	10,000	10,000
Series 94A Debt, variable rate due June 1, 2024 (c)	0.85%	2,855	2,855	2,855
Total Electric Utilities Debt		544,758	544,756	544,753
Total long-term debt		3,175,659	1,866,866	1,542,658
Less current maturities		—	—	—
Less deferred financing costs (d)		(16,604)	(13,184)	(11,286)
Long-term debt, net of current maturities		$ 3,159,055	$ 1,853,682	$ 1,531,372

(a) Long-term debt assumed with the SourceGas Acquisition.
(b) Variable interest rate, based on LIBOR plus a spread.
(c) Variable interest rate.
(d)

Includes deferred financing costs associated with our Revolving Credit Facility of $1.6 million, $1.7 million and $1.6 million as of March 31, 2016, December 31, 2015 and March 31, 2015, respectively.

(e) Currently unsecured, required to be ratably secured if Black Hills Gas Holdings incurs other secured indebtedness.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2016	$—
2017	$965,000
2018	$—
2019	$345,000
2020	$200,000
Thereafter	$1,668,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at March 31, 2016.

Debt Transactions

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. After discounts and underwriter fees, net proceeds from the offering totaled $546 million and were used as funding for the SourceGas Acquisition. The discounts will be 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 expense under this term loan is LIBOR plus a margin of 0.875%.

(11) EQUITY

A summary of the changes in equity is as follows:

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

Other stock transactions	(13)
Balance at March 31, 2016	$ 1,480,683

Three Months Ended March 31, 2015	Total Stockholders' Equity (in thousands)
Balance at December 31, 2014	$ 1,353,884
Net income (loss) available for common stock	33,850
Other comprehensive income	990
Dividends on common stock	(18,148)
Share-based compensation	209
Issuance of common stock	—
Dividend reinvestment and stock purchase plan	798
Other stock transactions	—
Balance at March 31, 2015	$ 1,371,583

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an at-the-market equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We have issued 121,000 common shares for $7.0 million, net of $0.1 million in fees and issuance costs with settlement dates through March 31, 2016 under the ATM equity offering program. Additionally, 140,000 shares for net proceeds of $8.4 million have been offered, but were not yet settled as of March 31, 2016.

(12) 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; and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable-rate debt and anticipated future refinancings.

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 13.

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 and related 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, terms of our commodity derivatives, and the derivative balances for our Oil and Gas segment reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	March 31, 2016		December 31, 2015		March 31, 2015	
	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps
Notional [(a)]	159,000	4,047,500	198,000	4,092,500	305,600	5,367,500
Maximum terms in months [(b)]	1	1	1	1	1	1
Derivative assets, current	$ —	$ —	$ —	$ —	$ —	$ —
Derivative assets, non-current	$ —	$ —	$ —	$ —	$ —	$ —
Derivative liabilities, current	$ —	$ —	$ —	$ —	$ —	$ —
Derivative liabilities, non-current	$ —	$ —	$ —	$ —	$ —	$ —

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(a) Crude oil in Bbls, natural gas in MMBtus.

(b) Refers to the tenor of the derivative instrument. Assets and liabilities are classified as current/non-current based on the production month hedged and the corresponding settlement of the derivative instrument.

Based on March 31, 2016 prices, a $7.6 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 for Electric Utility 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 were as follows, as of:

	March 31, 2016		December 31, 2015		March 31, 2015	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	18,270,000	57	20,580,000	60	17,280,000	69
Natural gas options purchased	990,000	21	2,620,000	3	1,320,000	12
Natural gas basis swaps purchased	16,810,000	57	18,150,000	60	15,735,000	57
Natural gas fixed for float swaps purchased [(b)]	2,374,000	23	—	0	—	0
Natural gas fixed for float swaps sold [(b)]	816,989	15	—	0	—	0
Natural gas physical purchases	2,948,250	12	—	0	—	0
Natural gas physical sales	813,200	11	—	0	—	0

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(a) Term reflects the maximum forward period hedged.

(b) 1,109,500 MMBtus and 112,500 MMBtus were designated as cash flow hedges for the natural gas swaps purchased and sold, respectively.

We had the following derivative balances related to the hedges in our Utilities reflected in our Condensed Consolidated Balance Sheets as of (in thousands):

	March 31, 2016	December 31, 2015	March 31, 2015
Derivative assets, current	$1,486	$—	$—
Derivative assets, non-current	$85	$—	$—
Derivative liabilities, current	$1,675	$—	$—
Derivative liabilities, non-current	$44	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$20,324	$23,578	$21,606

Financing Activities

We entered into pay fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated debt refinancings. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	March 31, 2016			December 31, 2015		March 31, 2015
	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	Interest Rate Swaps [(b)]
Notional	$150,000	$250,000	$75,000	$250,000	$75,000	$75,000
Weighted average fixed interest rate	2.09 %	2.29 %	4.97 %	2.29 %	4.97 %	4.97 %
Maximum terms in years	1.08	1.08	0.75	1.33	1.00	1.75
Derivative assets, non-current	$—	$—	$—	$3,441	$—	$—
Derivative liabilities, current	$—	$—	$2,290	$—	$2,835	$3,342
Derivative liabilities, non-current	$3,785	$10,693	$—	$—	$156	$2,143

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(a) These swaps are designated as cash flow hedges of anticipated debt refinancings.

(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 March 31, 2016 market interest rates and balances related to our interest rate swaps, a loss of approximately $2.3 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.

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 March 31, 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	$ (15,047)	Interest expense	$ 1,709		$ —
Commodity derivatives	1,589	Revenue	3,592		—
Commodity derivatives	238	Fuel, purchased power and cost of natural gas sold	57	Fuel, purchased power and cost of natural gas sold	—
Total	$ (13,220)		$ 5,358		$ —

Three Months Ended March 31, 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	$ (886)	Interest expense	$ 1,437		$ —
Commodity derivatives	3,764	Revenue	(3,932)		—
Total	$ 2,878		$ (2,495)		$ —

(13) 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, 8, 9 and 10 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 and basis swaps. 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 swaps, 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 on a daily basis. The fair value of these swaps include 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 March 31, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$ —	$ —	$ —	$ —	$ —
Basis Swaps -- Oil	—	4,668	—	(4,668)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	3,761	—	(3,761)	—
Commodity derivatives — Utilities	—	3,070	—	(1,499)	1,571
Interest Rate Swaps	—	—	—	—	—
Total	$ —	$ 11,499	$ —	$ (9,928)	$ 1,571
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$ —	$ —	$ —	$ —	$ —
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	250	—	(250)	—
Commodity derivatives — Utilities	—	23,428	—	(21,709)	1,719
Interest rate swaps	—	16,768	—	—	16,768
Total	$ —	$ 40,446	$ —	$ (21,959)	$ 18,487

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	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					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	6,309	—	(6,309)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	4,335	—	(4,335)	—
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					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- 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 March 31, 2015				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	8,096	—	(8,096)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	6,526	—	(6,526)	—
Commodity derivatives — Utilities	—	1,184	—	(1,184)	—
Interest Rate Swaps	—	—	—	—	—
Total	$—	$15,806	$—	$(15,806)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	2	—	(2)	—
Options -- Gas	—	—	—	—	—

Basis Swaps -- Gas	—	256	—	(256)	—
Commodity derivatives — Utilities	—	22,002	—	(22,002)	—
Interest rate swaps	—	5,485	—	—	5,485
Total	$ —	$ 27,745	$ —	$ (22,260)	$ 5,485

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. However, the amounts do not include net cash collateral on deposit in margin accounts at March 31, 2016, December 31, 2015, and March 31, 2015, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, 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 12.

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

As of March 31, 2016

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 7,986	$ —
Commodity derivatives	Derivative assets — non-current	607	—
Interest rate swaps	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	982
Commodity derivatives	Derivative liabilities — non-current	—	71
Interest rate swaps	Derivative liabilities — current	—	2,290
Interest rate swaps	Derivative liabilities — non-current	—	14,478
Total derivatives designated as hedges		$ 8,593	$ 17,821
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,326	$ —
Commodity derivatives	Derivative assets — non-current	79	—
Commodity derivatives	Derivative liabilities — current	—	9,117
Commodity derivatives	Derivative liabilities — non-current	—	12,009
Total derivatives not designated as hedges		$ 1,405	$ 21,126

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 March 31, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 9,989	$ —
Commodity derivatives	Derivative assets — non-current	4,633	—
Interest rate swaps	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	126
Commodity derivatives	Derivative liabilities — non-current	—	132
Interest rate swaps	Derivative liabilities — current	—	3,342
Interest rate swaps	Derivative liabilities — non-current	—	2,143
Total derivatives designated as hedges		$ 14,622	$ 5,743
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ —	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	7,530
Commodity derivatives	Derivative liabilities — non-current	—	13,288
Total derivatives not designated as hedges		$ —	$ 20,818

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 13, were as follows (in thousands) as of:

	March 31, 2016		December 31, 2015		March 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$46,974	$46,974	$456,535	$456,535	$63,385	$63,385
Restricted cash and equivalents [a]	$1,839	$1,839	$1,697	$1,697	$2,191	$2,191
Notes payable [a]	$215,600	$215,600	$76,800	$76,800	$102,600	$102,600
Long-term debt, including current maturities [b]	$3,159,055	$3,392,652	$1,853,682	$1,992,274	$1,531,372	$1,767,113

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

(b) 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.

(15) 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 March 31, 2016	March 31, 2015
Gains (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$(1,709)	$1,437
Commodity contracts	Revenue	(3,592)	(3,932)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(57)	—
		(5,358)	(2,495)
Income tax	Income tax benefit (expense)	1,946	1,254
Reclassification adjustments related to cash flow hedges, net of tax		$(3,412)	$(1,241)
Amortization of defined benefit plans:			
Prior service cost	Operations and maintenance	$(55)	$(55)
Actuarial gain (loss)	Operations and maintenance	494	705
		439	650
Income tax	Income tax benefit (expense)	(153)	(228)
Reclassification adjustments related to defined benefit plans, net of tax		$286	$422

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2014	$ 5,093	$ (20,137)	$ (15,044)
Other comprehensive income (loss), net of tax	595	395	990
Balance as of March 31, 2015	$ 5,688	$ (19,742)	$ (14,054)
Balance as of December 31, 2015	$ 6,725	$ (15,780)	$ (9,055)
Other comprehensive income (loss), net of tax	(12,056)	286	(11,770)
Balance as of March 31, 2016	$ (5,331)	$ (15,494)	$ (20,825)

(16) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three months ended	March 31, 2016	March 31, 2015
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$ 30,260	$ 33,534
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$ (15,528)	$ (10,909)
Income taxes, net	$ —	$ (2)

(17) 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.

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 regulated asset account and will be amortized over the average remaining service life of the plans.

Amounts recognized in the Condensed Consolidated Balance Sheet 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

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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. 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 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 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.

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

	Three Months Ended March 31,	
	2016	2015
Service cost	$2,078	$1,494
Interest cost	3,936	3,880
Expected return on plan assets	(5,765)	(4,867)
Prior service cost	15	15
Net loss (gain)	1,793	2,759
Net periodic benefit cost	$2,057	$3,281

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 VEBAs. Effective January 1, 2014, health care coverage for Medicare-eligible retirees is provided through an individual market health care exchange for BHC and Black Hills Utility Holdings retirees. SourceGas retirees do not participate in the individual market health care 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 March 31,	
	2016	2015
Service cost	$467	$464
Interest cost	485	450
Expected return on plan assets	(70)	(33)
Prior service cost (benefit)	(107)	(107)
Net loss (gain)	84	102
Net periodic benefit cost	$859	$876

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended March 31,	
	2016	2015
Service cost	$29	$491
Interest cost	314	364
Prior service cost	—	1
Net loss (gain)	207	270
Net periodic benefit cost	$550	$1,126

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 March 31, 2016	Additional Contributions Anticipated for 2016	Contributions Anticipated for 2017
$ —	$ 10,200	$ 10,200

Defined Benefit Pension Plans						
Non-pension Defined Benefit Postretirement Healthcare Plans	$	1,192	$	3,576	$	4,744
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$	392	$	1,176	$	1,627

(18) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 18 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 21.

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	$37,062	$45,248	$44,434	$40,636	$40,636	$192,651	$400,667
Facilities and equipment	1,755	2,216	2,207	1,676	1,359	3,326	12,539
Total	$38,817	$47,464	$46,641	$42,312	$41,995	$195,977	$413,206

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, 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 March 31, 2016, BHC’s guarantee was approximately $85 million. 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. The balance of the guarantee decreases as progress payments are made.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of March 31, 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 March 31, 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 March 31, 2016, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(19) 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 have recorded the following non-cash impairments of our oil and gas assets included in our Oil and Gas segment for the three months ended March 31, 2016 and March 31, 2015.

- During the first quarter of 2016, we recorded a $14 million pre-tax non-cash impairment of oil and gas assets included in our Oil and Gas segment. For natural gas, the average NYMEX price was $2.40 per Mcf, adjusted to $1.13 per Mcf at the wellhead; for crude oil, the average NYMEX price was $46.26 per barrel, adjusted to $39.80 per barrel at the wellhead.

- During the first quarter of 2015, we recorded a $22 million pre-tax non-cash impairment of oil and gas assets included in our Oil and Gas segment. For natural gas, the average NYMEX price was $3.88 per Mcf, adjusted to $2.69 per Mcf at the wellhead; for crude oil, the average NYMEX price was $82.72 per barrel, adjusted to $74.13 per barrel at the wellhead.

(20) INCOME TAXES

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

	Three Months Ended March 31,	
Tax (benefit) expense	2016	2015
Federal statutory rate	35.0 %	35.0 %
State income tax (net of federal tax effect)	2.6	1.2
Percentage depletion in excess of cost [(a)]	(14.1)	(1.0)
Accounting for uncertain tax positions adjustment [(b)]	(11.4)	1.9
Inter-period tax allocation	(4.0)	(1.5)
Transaction costs	2.5	—
Other tax differences	(1.0)	(1.2)
	9.6 %	34.4 %

(a) The tax benefit relates to additional percentage depletion deductions that are being claimed with respect to the oil and gas properties and represents a change in estimate for income tax accounting purposes. 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.

(b) 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 after-tax interest expense and tax credits that were previously accrued 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.

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 expect the reversal of approximately $26 million of the liability for unrecognized tax benefits to occur in 2016. The vast majority of such reversal will be 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 $11 million excluding interest.

(21) ACCRUED LIABILITIES

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

	March 31, 2016	December 31, 2015	March 31, 2015
Accrued employee compensation, benefits and withholdings	$90,295	$43,342	$32,090
Accrued property taxes	40,638	32,393	32,835
Accrued payments related to litigation expenses and settlements	—	38,750	25,000
Gas-gathering contract [(a)]	39,944	—	—
Customer deposits and prepayments	26,042	53,496	16,210
Accrued interest and contract adjustment payments	43,119	25,762	21,559
CIAC current portion	20,466	14,745	—
Other (none of which is individually significant)	11,677	23,573	39,087
Total accrued liabilities	$272,181	$232,061	$166,781

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(a) This contract was settled on April 29, 2016. See Note 22 for additional information.

(22) SUBSEQUENT EVENTS

Settlement of Gas Supply Contract

On April 29, 2016, we settled for $40 million a Black Hills Gas Holdings gas supply 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. 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 this contract vary, currently ranging from $6 to $8 per MMBtu and exceed 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 the net buyout costs associated with the contract termination to create a regulatory asset and recover the majority of costs over a five year period. At March 31, 2016, this payment was in Accrued liabilities on the Condensed Consolidated Balance Sheets.

Sale of Non-controlling 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%, non-controlling interest in Black Hills Colorado IPP for $215 million to AIA Energy North America LLC, an infrastructure investment platform managed by Argo Infrastructure Partners. FERC approval of the sale was received on March 29, 2016. Black Hills Colorado IPP continues to own 50.1% and 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.

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 our Energy Services, Service Guard and Tech Services product lines. Energy Services is a regulatory-approved program offered by our unregulated gas marketing affiliate providing approximately 59,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings. 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 customer-owned gas infrastructure facilities, typically through one-time contracts.

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

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

Oil and Gas: Our Oil and Gas segment engages in the production of crude oil and natural gas, primarily in the Rocky Mountain region. In 2015, we began transitioning the Oil and Gas segment to focus primarily on activities supporting utility cost of service gas programs.

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, other than the Oil and Gas segment, and in 2015 we began transitioning the Oil and Gas business to focus primarily on activities supporting cost of service gas programs.

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

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, 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 Electric Utilities Revenue, Gross Margin and Net Income by $16.5 million, $6.4 million and $1.4 million, respectively, for the three months ended March 31, 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 operations in South Dakota, Wyoming and Montana.
- Black Hills Energy Wyoming Electric - includes all Cheyenne Light's electric utility operations.
- Black Hills Energy Colorado Electric - includes all Colorado Electric's 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 73.

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

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015. Net income (loss) for the three months ended March 31, 2016 was $40 million, or $0.77 per share, compared to Net income (loss) of $34 million, or $0.76 per share, reported for the same period in 2015. The Net income (loss) for the three months ended March 31, 2016 increased over the same period in the prior year primarily due to higher earnings at our Gas Utilities, which include earnings of $7.6 million from our acquired SourceGas utilities since the acquisition date of February 12, 2016, and from approximately $11 million in tax benefits recognized 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 three months ended March 31, 2016 also included a non-cash after-tax ceiling test impairment of $8.8 million and after-tax SourceGas acquisition and transition costs of $15 million. The Net income (loss) for the three months ended March 31, 2015 included a non-cash after-tax ceiling test impairment of $14 million.

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

	Three Months Ended March 31,		
	2016	2015	Variance
Revenue			
Revenue	$485,714	$473,924	$11,790
Inter-company eliminations	(35,755)	(31,937)	(3,818)
	$449,959	$441,987	$7,972
Net income (loss)			
Electric Utilities	$19,215	$17,553	$1,662
Gas Utilities	31,975	23,588	8,387
Power Generation	8,582	8,145	437
Mining	2,938	3,010	(72)
Oil and Gas [(a)] [(b)]	(7,024)	(19,115)	12,091
	55,686	33,181	22,505
Corporate activities and eliminations [(c)] [(d)]	(15,684)	669	(16,353)
Net income attributable to non-controlling interest	(48)	—	(48)
Net income (loss) available for common stock	$40,002	$33,850	$6,152

(a) Net income (loss) for the three months ended March 31, 2016 and March 31, 2015 include non-cash after-tax ceiling test impairments of $8.8 million and $14 million, respectively. See Note 19 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) for the three months ended March 31, 2016 includes 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) for the three months ended March 31, 2016 included incremental, non-recurring acquisition and transition costs, after-tax of $15 million and after-tax internal labor costs attributable to the acquisition of $3.8 million. See Note 2 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(d) Net income (loss) for the three months ended March 31, 2016 includes 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 and Gas Utilities Segment

- Gas Utilities experienced milder weather during the three months ended March 31, 2016 compared to the three months ended March 31, 2015. Heating degree days were 23% lower for the three months ended March 31, 2016, compared to the same period in 2015. Heating degree days for the three months ended March 31, 2016 were 11% lower than normal, compared to 2% higher than normal for the same period in 2015.

- On May 3, 2016, Colorado Electric filed a request with the Colorado Public Utilities Commission to increase its net annual revenues by $8.9 million to recover investments in the $65 million, 40 MW natural gas-fired combustion turbine, currently under construction. Construction on the turbine continued in the first quarter of 2016. Through March 31, 2016, approximately $41 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 $1.1 million for the three months ended March 31, 2016.

- On September 30, 2015, Black Hills Corp.'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. We currently have hearing dates with the commissions in five states. The scheduled hearing for Nebraska is in May 2016, for Iowa in June 2016, for Wyoming in August 2016, and for Kansas and South Dakota in September 2016. We held preliminary settlement discussions with consumer advocate groups in Iowa, Nebraska, and Wyoming as well as with an intervenor, however, pre-hearing settlements are not likely. In April, the CPUC dismissed the Company's application indicating the need for more information regarding the property to be used and the impacts to customers. The company will evaluate alternatives upon receipt of the written order from the CPUC.

- 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 project is expected to be placed in service by the end of 2016.

- 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. The project is being built by Invenergy Wind Development Colorado LLC and is expected to be completed in the fourth quarter of 2016. 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.

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%, non-controlling interest in Black Hills Colorado IPP for $215 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 Colorado IPP will continue 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 commodity prices for crude oil and natural gas for the three months ended March 31, 2016 compared to the same period in 2015. The average hedged price received for natural gas decreased by 41% for the three months ended March 31, 2016 compared to the same period in 2015. The average hedged price received for oil decreased by 28% for the three months ended March 31, 2016 compared to the same period in 2015. Oil and Gas production volumes increased 6% for the three months ended March 31, 2016 compared to the same period 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 current quarter benefit 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 months ended March 31, 2016, our Oil and Gas segment recorded a pre-tax, non-cash ceiling test impairment of $14 million as a result of continued low commodity prices. Using our current reserves information, further ceiling test impairments will occur in the second quarter of 2016 if commodity prices for crude oil and natural gas remain at current levels.

Corporate Activities

- 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 20 for additional details on this settlement.

- 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 in 2016 and 2017. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Proceeds from the program will be used to fund capital expenditures and for general corporate purposes.

- 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. 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 has maintained a negative outlook as BHC focuses on integrating the newly acquired SourceGas assets over the 12 months subsequent to closing, consummation of the sale of the 49.9% non-controlling 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%, with a mandatory early termination date of April 12, 2017 to hedge the risks of interest rate movement between the hedge date and the expected pricing date for anticipated future long-term debt refinancings. This swap is accounted for as a cash flow hedge and any gain or loss is recorded in AOCI.

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, 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 March 31,		
	2016	2015	Variance
	(in thousands)		
Revenue	$167,276	$169,917	$(2,641)
Total fuel and purchased power	66,106	67,690	(1,584)
Gross margin	101,170	102,227	(1,057)
Operations and maintenance	39,325	41,237	(1,912)
Depreciation and amortization	21,258	20,268	990
Total operating expenses	60,583	61,505	(922)
Operating income	40,587	40,722	(135)
Interest expense, net	(12,499)	(13,254)	755
Other income (expense), net	655	74	581
Income tax benefit (expense)	(9,528)	(9,989)	461
Net income (loss)	$19,215	$17,553	$1,662

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Revenue - Electric (in thousands)	Three Months Ended March 31, 2016	2015
Residential:		
South Dakota Electric	$19,315	$20,140
Wyoming Electric	10,457	10,265
Colorado Electric	23,113	24,570
Total Residential	52,885	54,975
Commercial:		
South Dakota Electric	23,589	24,741
Wyoming Electric	15,673	15,820
Colorado Electric	22,483	22,164
Total Commercial	61,745	62,725
Industrial:		
South Dakota Electric	8,501	8,299
Wyoming Electric	10,097	8,626
Colorado Electric	9,265	10,756
Total Industrial	27,863	27,681
Municipal:		
South Dakota Electric	831	858
Wyoming Electric	511	516
Colorado Electric	2,695	3,062
Total Municipal	4,037	4,436
Total Retail Revenue - Electric	146,530	149,817
Contract Wholesale:		
Total Contract Wholesale - South Dakota Electric	4,174	5,420
Off-system Wholesale:		
South Dakota Electric	4,586	6,635
Wyoming Electric	1,846	1,961
Colorado Electric	134	84
Total Off-system Wholesale	6,566	8,680
Other Revenue:		
South Dakota Electric	7,646	4,190
Wyoming Electric	590	475
Colorado Electric	1,770	1,335
Total Other Revenue	10,006	6,000
Total Revenue - Electric	$167,276	$169,917

Quantities Generated and Purchased (in MWh)	Three Months Ended March 31, 2016	2015
Generated —		
Coal-fired:		
South Dakota Electric	388,001	376,834
Wyoming Electric	179,693	194,716
Total Coal-fired	567,694	571,550
Natural Gas and Oil:		
South Dakota Electric [(a)]	15,562	2,878
Wyoming Electric [(a)]	7,879	2,839
Colorado Electric	2,767	3,492
Total Natural Gas and Oil	26,208	9,209
Wind:		
Colorado Electric	13,061	9,091
Total Wind	13,061	9,091
Total Generated:		
South Dakota Electric	403,563	379,712
Wyoming Electric	187,572	197,555
Colorado Electric	15,828	12,583
Total Generated	606,963	589,850
Purchased —		
South Dakota Electric	339,690	438,443
Wyoming Electric	222,795	187,779
Colorado Electric	477,883	472,187
Total Purchased	1,040,368	1,098,409
Total Generated and Purchased:		
South Dakota Electric	743,253	818,155
Wyoming Electric	410,367	385,334
Colorado Electric	493,711	484,770
Total Generated and Purchased	1,647,331	1,688,259

(a) An increase in generation from Cheyenne Prairie was driven by outages at the Wyodak plant during the three months ended March 31, 2016.

	Three Months Ended March 31,	
Quantity Sold (in MWh)	2016	2015
Residential:		
South Dakota Electric	142,753	146,963
Wyoming Electric	68,313	67,499
Colorado Electric	149,028	157,214
Total Residential	360,094	371,676
Commercial:		
South Dakota Electric	188,888	195,078
Wyoming Electric	130,330	131,103
Colorado Electric	176,196	165,081
Total Commercial	495,414	491,262
Industrial:		
South Dakota Electric	108,021	111,859
Wyoming Electric	142,742	111,096
Colorado Electric [(a)]	99,489	118,107
Total Industrial	350,252	341,062
Municipal:		
South Dakota Electric	7,441	7,700
Wyoming Electric	2,545	2,550
Colorado Electric	26,583	28,113
Total Municipal	36,569	38,363
Total Retail Quantity Sold	1,242,329	1,242,363
Contract Wholesale:		
Total Contract Wholesale - South Dakota Electric [(b)]	63,453	84,271
Off-system Wholesale:		
South Dakota Electric	193,373	245,638
Wyoming Electric	37,493	48,872
Colorado Electric [(c)]	7,462	2,469
Total Off-system Wholesale	238,328	296,979
Total Quantity Sold:		
South Dakota Electric	703,929	791,509
Wyoming Electric	381,423	361,120
Colorado Electric	458,758	470,984
Total Quantity Sold	1,544,110	1,623,613
Other Uses, Losses or Generation, net [(d)]:		
South Dakota Electric	39,324	26,646
Wyoming Electric	28,944	24,214
Colorado Electric	34,953	13,786

Total Other Uses, Losses and Generation, net	103,221	64,646
Total Energy	1,647,331	1,688,259

(a) Decrease was due to a planned outage at a large industrial customer during the three months ended March 31, 2016.
(b) Decrease was driven by load requirements related to a unit-contingent PPA.
(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 March 31, 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	2,806	(13)%	(2)%	2,873	(11)%
Wyoming Electric	2,776	(10)%	5%	2,651	(12)%
Colorado Electric	2,285	(12)%	(5)%	2,398	(8)%
Combined [(a)]	2,561	(12)%	(2)%	2,610	(10)%

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

Electric Utilities Power Plant Availability	Three Months Ended March 31,	
	2016	2015
Coal-fired plants	93.9%	91.3%
Other plants	95.0%	95.7%
Total availability	94.6%	94.1%

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015: Net income for the Electric Utilities was $19 million for the three months ended March 31, 2016, compared to Net income of $18 million for the three months ended March 31, 2015, as a result of:

Gross margin decreased primarily due to lower retail load and demand that decreased residential margins by $1.1 million. The prior year included a $2.1 million benefit 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. Partially offsetting these decreases were favorable rider margins of $0.9 million driven primarily by our construction and TCA riders, and $0.6 million from an additional day as a result of leap-year.

Operations and maintenance decreased primarily due to lower employee costs as a result of integration activities and transition expenses allocated to the Corporate segment.

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

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

Other income (expense), net increased primarily due to higher other income than the same period in the prior year.

Income tax benefit (expense): The effective tax rate decreased due primarily to a favorable re-measurement of an uncertain tax position liability involving research and development credits and deductions as a result of an agreement reached during the first quarter of 2016 with the IRS.

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Gas Utilities

	Three Months Ended March 31,		
	2016	2015	Variance
	(in thousands)		
Revenue:			
Natural gas — regulated	$249,911	$245,629	$4,282
Other — non-regulated services	20,562	8,503	12,059
Total revenue	270,473	254,132	16,341
Cost of sales			
Natural gas — regulated	128,899	162,383	(33,484)
Other — non-regulated services	9,065	3,913	5,152
Total cost of sales	137,964	166,296	(28,332)
Gross margin	132,509	87,836	44,673
Operations and maintenance	52,687	38,179	14,508
Depreciation and amortization	15,972	7,822	8,150
Total operating expenses	68,659	46,001	22,658
Operating income (loss)	63,850	41,835	22,015
Interest expense, net	(13,517)	(4,388)	(9,129)
Other income (expense), net	651	(16)	667
Income tax benefit (expense)	(19,009)	(13,843)	(5,166)
Net income (loss)	$31,975	$23,588	$8,387

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

System Infrastructure (in line miles) as of March 31, 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

	Three Months Ended March 31,	
Revenue (in thousands)	2016	2015
Residential:		
Arkansas	$15,778	$—
Colorado	31,780	25,736
Nebraska	46,534	56,444
Iowa	34,847	46,366
Kansas	22,348	29,328
Wyoming	13,547	8,712
Total Residential	$164,834	$166,586
Commercial:		
Arkansas	$7,672	$—
Colorado	10,207	5,097
Nebraska	13,083	18,212
Iowa	15,137	21,629
Kansas	8,170	11,066
Wyoming	5,703	4,954
Total Commercial	$59,972	$60,958
Industrial:		
Arkansas	$837	$—
Colorado	245	29
Nebraska	118	317
Iowa	575	1,255
Kansas	630	1,741
Wyoming	954	1,900
Total Industrial	$3,359	$5,242
Transportation:		
Arkansas	$1,635	$—
Colorado	936	365
Nebraska	7,789	5,396
Iowa	1,475	1,662
Kansas	2,043	2,501
Wyoming	2,615	—
Total Transportation	$16,493	$9,924

	Three Months Ended March 31,	
Revenue (in thousands) (continued)	2016	2015
Transmission:		
Nebraska	$27	$—
Wyoming	337	—
Total Transmission	$364	$—
Pipeline Revenue	$647	$—
Other Sales Revenue:		
Arkansas	$825	$—
Colorado	107	43
Nebraska	801	657
Iowa	100	139
Kansas	1,990	1,165
Wyoming	419	915
Total Other Sales Revenue	$4,242	$2,919
Total Regulated Revenue	$249,911	$245,629
Non-regulated Services	20,562	8,503
Total Revenue	$270,473	$254,132

	Three Months Ended March 31,	
Gross Margin (in thousands)	2016	2015
Residential:		
Arkansas	$9,629	$—
Colorado	11,477	6,337
Nebraska	22,472	18,990
Iowa	13,607	13,898
Kansas	10,085	11,478
Wyoming	8,731	3,778
Total Residential	$76,001	$54,481
Commercial:		
Arkansas	$3,976	$—
Colorado	3,165	1,040
Nebraska	4,457	4,669
Iowa	4,289	4,636
Kansas	2,911	3,387
Wyoming	2,664	1,428
Total Commercial	$21,462	$15,160

	Three Months Ended March 31,	
Gross Margin (in thousands) (continued)	2016	2015
Industrial:		
Arkansas	$318	$—
Colorado	111	21
Nebraska	45	81
Iowa	43	81
Kansas	229	393
Wyoming	203	262
Total Industrial	$949	$838
Transportation:		
Arkansas	$1,635	$—
Colorado	936	365
Nebraska	7,789	5,396
Iowa	1,475	1,662
Kansas	2,043	2,501
Wyoming	2,615	—
Total Transportation	$16,493	$9,924
Transmission:		
Nebraska	$27	$—
Wyoming	277	—
Total Transmission	$304	$—
Pipeline	$706	$—
Other Sales Margins:		
Arkansas	$825	$—
Colorado	107	43
Nebraska	801	657
Iowa	100	139
Kansas	1,979	1,089
Wyoming	419	915
Total Other Sales Margins	$4,231	$2,843
Total Regulated Gross Margin	$120,146	$83,246
Non-regulated Services	12,363	4,590
Total Gross Margin	$132,509	$87,836

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended March 31, 2016	2015
Residential:		
Arkansas	1,893,080	—
Colorado	4,417,834	2,946,805
Nebraska	6,441,093	5,958,956
Iowa	5,038,749	5,516,037
Kansas	2,918,074	3,353,814
Wyoming	2,436,850	940,407
Total Residential	23,145,680	18,716,019
Commercial:		
Arkansas	1,140,339	—
Colorado	1,444,537	617,198
Nebraska	1,990,729	2,180,694
Iowa	2,573,951	2,880,091
Kansas	1,274,888	1,435,504
Wyoming	1,151,727	670,589
Total Commercial	9,576,171	7,784,076
Industrial:		
Arkansas	161,691	—
Colorado	37,977	2,402
Nebraska	18,337	45,700
Iowa	127,199	191,005
Kansas [(a)]	164,345	324,779
Wyoming	272,525	301,277
Total Industrial	782,074	865,163
Wholesale and Other:		
Arkansas	13,235	—
Kansas [(b)]	—	13,975
Total Wholesale and Other	13,235	13,975
Total Distribution Quantities Sold	33,517,160	27,379,233
Transportation:		
Arkansas	1,411,592	—
Colorado	798,593	380,049
Nebraska	11,214,496	9,049,775
Iowa	5,830,344	6,088,049
Kansas	3,813,385	4,297,352
Wyoming	4,536,169	—
Total Transportation	27,604,579	19,815,225
Total Distribution Quantities Sold and Transportation	61,121,739	47,194,458

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(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 March 31,				
	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]	957	(16)%	N/A	N/A	N/A
Colorado	2,628	(9)%	4%	2,535	(9)%
Nebraska	2,681	(13)%	(11)%	3,014	(1)%
Iowa	3,082	(9)%	(20)%	3,834	14%
Kansas [a]	2,163	(13)%	(7)%	2,322	(6)%
Wyoming	2,849	(8)%	7%	2,651	(12)%
Combined [b]	2,449	(11)%	(23)%	3,177	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.

Results of Operations for the Gas Utilities for the Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015: Net income for the Gas Utilities was $32 million for the three months ended March 31, 2016, compared to Net income of $24 million for the three months ended March 31, 2015, as a result of:

Gross margin increased primarily due to margins of approximately $46 million contributed by the SourceGas utilities acquired on February 12, 2016. An additional margin increase of $1.8 million was attributable to year-over-year customer growth primarily from our 2015 Wyoming gas system acquisitions. Partially offsetting these increases was a $2.8 million decrease due to weather. Heating degree days were 23% lower for the three months ended March 31, 2016, compared to the same period in the prior year and 11% lower than normal in the current year, compared to 2% higher than normal in the prior year.

Operations and maintenance increased primarily due to additional operating costs of approximately $18 million for the acquired SourceGas utilities. Partially offsetting this increase were lower employee costs primarily due to integration and transition expenses allocated to our Corporate segment, and lower property taxes at our Kansas utility.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities of approximately $7.1 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 from the acquired SourceGas utilities of approximately $8.8 million.

Other income (expense), net increased primarily due to higher other income than 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 net 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.

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)	2/2015	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

(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.

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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	10/2015	2/2016	$ 3.8	$ 3.8
Wyoming Gas [(d)]	Gas	2/2010	1/2011	$ 7.5	$ 4.3
Colorado Gas [(e)]	Gas	6/2010	12/2010	$ 6.0	$ 2.8

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(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 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 November 1, 2015, Nebraska Gas filed with the NPSC requesting recovery of $3.8 million related to system safety and integrity expenditures expected to be incurred in 2016. The SSIR tariff was approved by the NPSC on January 12, 2016 to go into effect on February 1, 2016.

(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, Black Hills Corp.'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. If approved, our utilities will acquire natural gas reserves and/or drill wells to produce natural gas for the program for up to 50% of weather normalized annual firm demand. The proposed Cost of Service Gas Program model has a capital structure of 50% equity and 50% debt, and seeks a utility-like return. Based on the historical price volatility for natural gas, the Cost of Service Gas Program should result in more stable prices and carries a reasonable expectation of lower prices over the long term.

We currently have hearing dates with the commissions in five states. The scheduled hearing for Nebraska is in May 2016, for Iowa in June 2016, for Wyoming in August 2016, and for South Dakota and Kansas in September 2016. The program is not necessarily dependent on approvals from all states, however, the total program volumes depend on the sum of volumes approved by the various state commissions. Our long-term target for the program is up to 50% of annual demand for our gas utilities and gas-fired electric generation.

The initial applications seek approval of the framework of the program, including approval of the proposed cost of service gas agreement, acquisition and drilling criteria; approval of recovery through existing fuel adjustment tariffs; hedge participation level, and if necessary, waiver of affiliate rules. After initial approvals, we will seek approval for acquisition of a specific property for inclusion in the COSG Program under the established criteria. We have had preliminary settlement discussions with consumer advocate groups and an intervenor in Iowa, Nebraska, and Wyoming, although pre-hearing settlements are not likely. In April, the CPUC dismissed the Company’s application indicating the need for more information regarding the property to be used and the impacts to customers. The company will evaluate alternatives upon receipt of the written order from the CPUC.

Power Generation

	Three Months Ended March 31,		
	2016	2015	Variance
	(in thousands)		
Revenue	$23,308	$22,674	$ 634
Operations and maintenance	8,042	7,828	214
Depreciation and amortization	1,031	1,134	(103)
Total operating expense	9,073	8,962	111
Operating income	14,235	13,712	523
Interest expense, net	(814)	(886)	72
Other (expense) income, net	23	(2)	25
Income tax (expense) benefit	(4,862)	(4,679)	(183)
Net income (loss)	$8,582	$8,145	$ 437

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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.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended March 31,	
	2016	2015
Quantities Sold, Generated and Purchased (MWh) [(a)]		
Sold		
Black Hills Colorado IPP	333,878	284,491
Black Hills Wyoming [(b)]	167,031	159,558
Total Sold	500,909	444,049
Generated		
Black Hills Colorado IPP	333,878	284,491
Black Hills Wyoming	138,919	137,973
Total Generated	472,797	422,464
Purchased		
Black Hills Wyoming [(b)]	28,303	24,392
Total Purchased	28,303	24,392

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(a) Company use 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.

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

	Three Months Ended March 31,	
	2016	2015
Contracted power plant fleet availability:		
Coal-fired plant	97.8%	98.2%
Natural gas-fired plants	99.3%	98.9%
Total availability	98.9%	98.7%

Results of Operations for Power Generation for the Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015: Net income for the Power Generation segment was $8.6 million for the three months ended March 31, 2016, compared to Net income of $8.1 million for the same period in 2015 as a result of:

Revenue increased primarily due to an increase in PPA pricing and an increase in MWh sold, partially offset by a decrease in off-system sales quantities and market prices associated with our economy energy PPA.

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 was comparable to the same period in the prior year.

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 prior year.

Mining

	Three Months Ended March 31,		
	2016	2015	Variance
	(in thousands)		
Revenue	$16,282	$15,934	$ 348
Operations and maintenance	10,434	9,904	530
Depreciation, depletion and amortization	2,479	2,503	(24)
Total operating expenses	12,913	12,407	506
Operating income (loss)	3,369	3,527	(158)
Interest (expense) income, net	(92)	(89)	(3)
Other income, net	534	585	(51)
Income tax benefit (expense)	(873)	(1,013)	140
Net income (loss)	$2,938	$3,010	$ (72)

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

	Three Months Ended March 31,	
	2016	2015
Tons of coal sold	1,002	1,019
Cubic yards of overburden moved [(a)]	1,765	1,413
Revenue per ton	$16.25	$15.64

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

Results of Operations for Mining for the Three Months Ended March 31, 2016 Compared to the Three Months Ended March 31, 2015: Net income for the Mining segment was $2.9 million for the three months ended March 31, 2016, compared to Net income of $3.0 million for the same period in 2015 as a result of:

Revenue increased primarily due to a 4% increase in price per ton sold, partially offset by a 2% decrease in tons 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 increased primarily due to mining in areas with higher overburden, partially offset by lower fuel costs.

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 current year re-measurement of the liability for uncertain tax positions involving research and development tax credits and deductions.

Oil and Gas

	Three Months Ended March 31,		
	2016	2015	Variance
	(in thousands)		
Revenue	$8,375	$11,267	$(2,892)
Operations and maintenance	9,035	10,917	(1,882)
Depreciation, depletion and amortization	4,113	7,512	(3,399)
Impairment of long-lived assets	14,496	22,036	(7,540)
Total operating expenses	27,644	40,465	(12,821)
Operating income (loss)	(19,269)	(29,198)	9,929
Interest income (expense), net	(1,074)	(384)	(690)
Other income (expense), net	39	(223)	262
Income tax benefit (expense)	13,280	10,690	2,590
Net income (loss)	$(7,024)	$(19,115)	$12,091

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

	Three Months Ended March 31,	
	2016	2015
Production:		
Bbls of oil sold	98,067	80,730
Mcf of natural gas sold	2,286,606	2,254,042
Bbls of NGL sold	37,003	28,770
Mcf equivalent sales	3,097,026	2,911,043

	Three Months Ended March 31,	
	2016	2015
Average price received: (a) (b)		
Oil/Bbl	$47.83	$66.86
Gas/Mcf	$1.30	$2.20
NGL/Bbl	$10.36	$13.74
Depletion expense/Mcfe	$0.93	$2.20

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(a) Net of hedge settlement gains and losses.

(b) Ceiling test impairments of $14 million and $22 million were recorded for the three months ended March 31, 2016 and March 31, 2015, respectively.

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

	Three Months Ended March 31, 2016				Three Months Ended March 31, 2015			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation (a)	Production Taxes	Total
San Juan	$1.75	$ 1.09	$ 0.32	$3.16	$1.58	$ 1.30	$ 0.37	$3.25
Piceance	0.34	1.94	0.13	2.41	0.33	2.48	0.20	3.01
Powder River	2.62	—	0.56	3.18	2.89	—	0.56	3.45
Williston	0.95	—	0.32	1.27	0.24	—	0.09	0.33
All other properties	0.56	—	0.04	0.60	1.24	—	0.34	1.58
Total weighted average	$1.09	$ 1.15	$ 0.25	$2.49	$1.19	$ 1.35	$ 0.31	$2.85

(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 natural gas production in our 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 March 31, 2016 Compared to the Three Months Ended March 31, 2015: Net loss for the Oil and Gas segment was $7.0 million for the three months ended March 31, 2016, compared to Net loss of $19 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 28% decrease in the average hedged price received for crude oil sold, and a 41% decrease in the average hedged price received for natural gas sold. A production increase of 6%, driven primarily by wells placed on production in 2015, partially offset the decrease in prices.

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 write-down of $14 million in the first quarter of 2016 reflected a trailing 12 month average NYMEX natural gas price of $2.40 per Mcf, adjusted to $1.13 per Mcf at the wellhead, and $46.26 per barrel for crude oil, adjusted to $39.80 per barrel at the wellhead, compared to the $22 million write-down in the same period of the prior year which reflected a trailing 12 month average NYMEX natural gas price of $3.88 per Mcf, adjusted to $2.69 per Mcf at the wellhead, and $82.72 per barrel for crude oil, adjusted to $74.13 per barrel at the wellhead.

Interest income (expense), net increased primarily due to a 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 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 March 31, 2016 Compared to the Three Months Ended March 31, 2015: Net loss for Corporate was $16 million for the three months ended March 31, 2016, compared to Net income of $0.7 million for the three months ended March 31, 2015. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition including approximately $15 million of after-tax acquisition and transition costs, and approximately $3.8 million of after-tax internal labor that otherwise would have been charged to other business segments, during the three months ended March 31, 2016. A tax benefit of approximately $4.4 million was recognized during the three months ended March 31, 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 those disclosed 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. Our significant assumptions and estimates can include, but are not limited to, the cash flows that an acquired entity is expected to generate in the future, the appropriate weighted-average cost of capital, and the savings expected to be derived from the business combination. 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 borrowings. 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 maintains 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 March 31, 2016, we had $2.5 million of collateral posted related to our wholesale commodity contracts transactions, and no collateral posted related to our interest rate swaps. At March 31, 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 three months ended March 31 (in thousands):

Cash provided by (used in):	2016	2015	Increase (Decrease)
Operating activities	$138,337	$151,487	$(13,150)
Investing activities	$(1,216,532)	$(117,871)	$(1,098,661)
Financing activities	$668,634	$8,551	$660,083

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

Operating Activities

Net cash provided by operating activities was $138 million for the three months ended March 31, 2016, compared to net cash provided by operating activities of $151 million for the same period in 2015 for a variance of $13 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $12 million higher for the three months ended March 31, 2016 compared to the same period in the prior year; and

- Net cash inflows from operating assets and liabilities were $10 million for the three months ended March 31, 2016, compared to net cash inflows of $29 million in the same period in the prior year. This $19 million variance was primarily due to:

- Cash inflows increased by approximately $14 million for the three months ended March 31, 2016 compared to the same period in the prior year primarily as a result of changes in accounts receivable;

- Cash inflows decreased by approximately $9.0 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; and

- Cash outflows increased by approximately $24 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 in the three months ended March 31, 2016; and

- Cash outflows increased by approximately $6 million primarily driven by changes in other regulatory liabilities.

Investing Activities

Net cash used in investing activities was $1.217 billion for the three months ended March 31, 2016, compared to net cash used in investing activities of $118 million for the same period in 2015. The variance was primarily driven by:

- Cash outflows of $1.132 billion for the acquisition of SourceGas, net of $2 million cash received and $760 million of long term debt assumed. See Note 2; and

- Capital expenditures of approximately $84 million for the three months ended March 31, 2016 compared to $118 million for the three months ended March 31, 2015. The decrease is primarily due to higher capital expenditures of approximately $58 million at our Oil and Gas segment in the prior year driven by drilling and completion activity in the Piceance basin. This is partially offset by a $22 million increase in capital expenditures at our Gas Utility segment, driven primarily by the addition of the Black Hills Gas Holdings utilities.

Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2016 was $669 million, compared to $8.6 million of net cash provided by financing activities for the same period in 2015. The variance was primarily driven by:

- Net long-term borrowings increased by $546 million due to our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition;

- Net short-term borrowings under the revolving credit facility for the three months ended March 31, 2016 were $111 million higher than the prior year primarily due to these proceeds being used to partially fund the SourceGas Acquisition and to higher working capital requirements in the current year than in the same period in the prior year;

- Proceeds of $7.0 million from our ATM equity offering program; and

- Increased dividend payments of approximately $3.4 million.

Dividends

Dividends paid on our common stock totaled $22 million for the three months ended March 31, 2016, or $0.42 per share. On April 25, 2016, our board of directors declared a quarterly dividend of $0.42 per share payable June 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 June 26, 2015, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through June 26, 2020. 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 the capacity of the facility to $750 million. 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 and 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. Pricing remains unchanged from the previous agreement. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating.

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

Credit Facility	Expiration	Current Capacity	Borrowings at March 31, 2016	Letters of Credit at March 31, 2016	Available Capacity at March 31, 2016
Revolving Credit Facility	June 26, 2020	$ 500	$ 216	$ 24	$ 260

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain Recourse Leverage Ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit, and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of March 31, 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 0.8 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 $2.3 million at March 31, 2016.

We have a 10-year $150 million notional forward starting interest rate swap at an all-in rate of 2.09% and a 10-year, $250 million notional forward starting interest rate swap at an all-in rate of 2.29% to hedge the risks of interest rate movement between their initial hedge dates and the expected pricing date for anticipated future long-term debt refinancings in late 2016 and 2017. These swaps are accounted for as cash flow hedges with any gain or loss initially recorded in AOCI. Both swaps have a mandatory early termination date of April 12, 2017. The mark-to-market value of these swaps was a liability of $14 million at March 31, 2016.

Financing Activities

On March 18, 2016, we implemented an at-the-market 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. We have issued 121,000 common shares for $7.0 million, net of $0.1 million in fees and issuance costs with settlement dates through March 31, 2016 under the ATM equity offering program. 140,000 shares for net proceeds of $8.4 million have been offered, but were not yet settled as of March 31, 2016. Proceeds from the ATM equity offering program were used to fund capital expenditures and for general corporate purposes.

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, non-controlling interest in Black Hills Colorado IPP for approximately $215 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. Applying these proceeds against our March 31, 2016 debt balances would have resulted in a 140 basis point reduction in our net debt to equity ratio.

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

- 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 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. Each equity unit has a stated amount of $50 and consists of a contract to (i) 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:

- $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 is 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% to hedge the risks of interest rate movement between the hedge date and the expected pricing date for anticipated future long-term debt refinancings in late 2016 or 2017. The swap is accounted for as a cash flow hedge with any gain or loss recorded in AOCI. The swap has a mandatory early termination date of April 12, 2017.

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 date and the expected pricing date for anticipated future long-term debt refinancings in late 2016 or 2017. The swap is accounted for as a cash flow hedge with any gain or loss recorded in AOCI. The swap has a mandatory early termination date of April 12, 2017.

Future Financing Plans

We anticipate the following financing activities:

- Continue our At-the-Market equity offering program to issue up to $200 million of common stock through 2017;
- Evaluate extending and upsizing our existing $500 million Revolving Credit Facility and implementing a commercial paper program; and
- Evaluate alternatives for refinancing over $1 billion of near-term debt maturities.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of March 31, 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 is a Recourse Leverage Ratio, which on February 12, 2016, increased upon closing of the SourceGas Acquisition to 0.75 to 1.00 for the next four fiscal quarters; it was previously 0.65 to 1.00. Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of March 31, 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 March 31, 2016:

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

(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 March 31, 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.

The following table represents the credit ratings of Black Hills Gas at March 31, 2016:

Rating Agency	Senior Unsecured Rating	Outlook
S&P	BBB	Stable
Moody's	Baa1	Stable
Fitch	BBB+	Positive

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 Three Months Ended March 31, 2016 [a]	Total 2016 Planned Expenditures [b][c]	Total 2017 Planned Expenditures	Total 2018 Planned Expenditures
Electric Utilities [c]	$ 41,283	$ 324,000	$ 140,000	$ 148,000
Gas Utilities [d]	22,680	163,000	179,000	156,000
Power Generation	1,219	4,000	5,000	1,000
Mining	398	6,000	7,000	7,000
Oil and Gas	—	14,000	10,000	10,000
Corporate	10,674	10,000	10,000	9,000
	$ 76,254	$ 521,000	$ 351,000	$ 331,000

(a) Expenditures for the three months ended March 31, 2016 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the three months ended March 31, 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 of Colorado Electric’s 40 MW natural gas fired generating unit.
(d) Includes planned expenditures for Black Hills Gas Holdings of $107 million, $105 million and $78 million for 2016, 2017 and 2018, respectively.

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 March 31, 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 Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[a][b]	$3,178,855	$—	$965,000	$545,000	$1,668,855
Unconditional purchase obligations[c]	964,783	154,016	357,133	235,253	218,381
Operating lease obligations[d]	29,574	4,662	11,114	4,999	8,799
Other long-term obligations[e]	45,642	—	—	—	45,642
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	215,600	215,600	—	—	—
Total contractual cash obligations[h]	$4,627,494	$416,422	$1,386,998	$817,384	$2,006,690

(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: $96 million in 2016, $110 million in 2017, $97 million in 2018, $94 million in 2019 and $87 million in 2020. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of March 31, 2016.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas purchases, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charge under the PPAs and the commodity price under the gas purchase contracts 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 March 31, 2016. Our transmission obligations are based on filed tariffs as of December 31, 2015. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. 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 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 20 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 March 31, 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.

Guarantees

Other than those disclosed in Note 18 of the Notes to the Condensed Consolidated Financial Statements on Form 10Q, 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 inc statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 2 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

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

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

	March 31, 2016	December 31, 2015	March 31, 2015
Net derivative (liabilities) assets	$(20,066)	$(22,292)	$(20,818)
Cash collateral offset in Derivatives	20,210	22,292	20,818
Cash Collateral included in Other current assets	3,024	5,367	3,818
Net asset (liability) position	$3,168	$5,367	$3,818

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 March 31, 2016, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2016					
Swaps - MMBtu	—				