BLACK HILLS CORP /SD/
Form 10-Q
November 04, 2015

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

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

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

Class	Outstanding at October 31, 2015	
Common stock, $1.00 par value	44,850,752	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
Bbl	Barrel
BHC	Black Hills Corporation; the Company
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 Black Hills Utility Holdings, Inc., and its subsidiaries
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
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
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
Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural gas-fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
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.
EPA	United States Environmental Protection Agency

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.
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.
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)
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 September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in thousands, except per share amounts)			
Revenue	$272,105	$272,087	$986,346	$1,015,493
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of natural gas sold	71,627	84,674	350,778	416,473
Operations and maintenance	67,282	64,245	205,630	201,546
Non-regulated energy operations and maintenance	22,548	20,170	67,744	63,852
Depreciation, depletion and amortization	37,768	36,628	116,821	107,754
Taxes - property, production and severance	10,675	11,082	33,988	32,462
Impairment of long-lived assets	61,875	—	178,395	—
Other operating expenses	2,374	49	3,392	323
Total operating expenses	274,149	216,848	956,748	822,410
Operating income (loss)	(2,044)	55,239	29,598	193,083
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(22,378)	(17,919)	(61,833)	(53,665)
Allowance for funds used during construction - borrowed	478	319	843	845
Capitalized interest	280	231	1,037	734
Interest income	414	575	1,163	1,541
Allowance for funds used during construction - equity	430	297	563	828
Other income (expense), net	842	261	1,568	1,262
Total other income (expense), net	(19,934)	(16,236)	(56,659)	(48,455)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	(21,978)	39,003	(27,061)	144,628
Equity in earnings (loss) of unconsolidated subsidiaries	—	—	(344)	(1)
Impairment of equity investments	—	—	(5,170)	—
Income tax benefit (expense)	12,035	(11,640)	14,640	(48,272)
Net income (loss) available for common stock	$(9,943)	$27,363	$(17,935)	$96,355
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic	$(0.22)	$0.62	$(0.40)	$2.17
Earnings (loss) per share, Diluted	$(0.22)	$0.61	$(0.40)	$2.16
Weighted average common shares outstanding:				
Basic	44,635	44,415	44,598	44,382
Diluted	44,635	44,608	44,598	44,584

Dividends declared per share of common stock	$0.405	$0.390	$1.215	$1.170

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

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

(unaudited)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Net income (loss) available for common stock	$(9,943)	$27,363	$(17,935)	$96,355
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $(1,609) and $(1,840) for the three months ended 2015 and 2014 and $(1,482) and $582 for the nine months ended 2015 and 2014, respectively)	2,773	3,145	2,644	(1,071)
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $558 and $(732) for the three months ended 2015 and 2014 and $2,548 and $(1,931) for the nine months ended 2015 and 2014, respectively)	(948)	1,328	(3,450)	3,511
Benefit plan liability adjustments - net gain (loss) (net of tax (expense) benefit of $0 and $0 for the three months ended 2015 and 2014 and $16 and $2 for the nine months ended 2015 and 2014, respectively)	—	—	(27)	(2)
Benefit plan liability tax adjustments - net gain (loss)	—	—	—	(394)
Benefit plan liability adjustments - prior service cost (net of tax (expense) benefit of $0 and $0 for the three months ended 2015 and 2014 and $0 and $(90) for the nine months ended 2015 and 2014, respectively)	—	—	—	164
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $19 and $17 for the three months ended 2015 and 2014 and $58 and $60 for the nine months ended 2015 and 2014, respectively)	(36)	(31)	(108)	(110)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(247) and $(86) for the three months ended 2015 and 2014 and $(742) and $(262) for the nine months ended 2015 and 2014, respectively)	459	160	1,374	485
Other comprehensive income (loss), net of tax	2,248	4,602	433	2,583
Comprehensive income (loss) available for common stock	$(7,695)	$31,965	$(17,502)	$98,938

See Note 13 for additional disclosures.

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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of September 30, 2015	December 31, 2014	September 30, 2014
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$38,841	$21,218	$11,939
Restricted cash and equivalents	2,462	2,056	1,918
Accounts receivable, net	115,502	189,992	123,399
Materials, supplies and fuel	90,349	91,191	105,726
Derivative assets, current	—	—	—
Income tax receivable, net	—	2,053	1,268
Deferred income tax assets, net, current	47,783	48,288	34,756
Regulatory assets, current	51,962	74,396	68,444
Other current assets	55,383	24,842	26,502
Total current assets	402,282	454,036	373,952
Investments	12,148	17,294	17,144
Property, plant and equipment	4,882,420	4,563,400	4,493,696
Less: accumulated depreciation and depletion	(1,617,723)	(1,357,929)	(1,373,247)
Total property, plant and equipment, net	3,264,697	3,205,471	3,120,449
Other assets:			
Goodwill	359,527	353,396	353,396
Intangible assets, net	3,440	3,176	3,231
Regulatory assets, non-current	182,337	183,443	140,422
Derivative assets, non-current	—	—	—
Other assets, non-current	22,131	29,086	29,930
Total other assets, non-current	567,435	569,101	526,979
TOTAL ASSETS	$4,246,562	$4,245,902	$4,038,524

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

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

	As of September 30, 2015	December 31, 2014	September 30, 2014
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$91,633	$124,139	$100,444
Accrued liabilities	229,957	170,115	163,374
Derivative liabilities, current	3,312	3,340	3,397
Accrued income taxes, net	308	—	—
Regulatory liabilities, current	5,647	3,687	828
Notes payable	117,900	75,000	184,000
Current maturities of long-term debt	—	275,000	275,000
Total current liabilities	448,757	651,281	727,043
Long-term debt, net of current maturities	1,567,797	1,267,589	1,107,519
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	494,834	511,952	494,095
Derivative liabilities, non-current	722	2,680	3,273
Regulatory liabilities, non-current	152,164	145,144	118,856
Benefit plan liabilities	158,614	158,966	108,924
Other deferred credits and other liabilities	136,462	154,406	144,089
Total deferred credits and other liabilities	942,796	973,148	869,237
Commitments and contingencies (See Notes 2, 9, 10, 15, 16)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,891,626; 44,714,072; and 44,696,670 shares, respectively	44,892	44,714	44,697
Additional paid-in capital	753,856	748,840	746,575
Retained earnings	504,864	577,249	560,133
Treasury stock, at cost – 36,711; 42,226; and 41,552 shares, respectively	(1,789)	(1,875)	(1,841)
Accumulated other comprehensive income (loss)	(14,611)	(15,044)	(14,839)
Total stockholders' equity	1,287,212	1,353,884	1,334,725
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,246,562	$4,245,902	$4,038,524

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Nine Months Ended September 30,	
	2015	2014
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$(17,935)	$96,355
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	116,821	107,754
Deferred financing cost amortization	3,074	1,608
Impairment of long-lived assets	183,565	—
Derivative fair value adjustments	(8,851)	2,136
Stock compensation	2,868	6,978
Deferred income taxes	(20,808)	48,930
Employee benefit plans	15,175	11,109
Other adjustments, net	4,013	2,016
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	3,618	(17,248)
Accounts receivable, unbilled revenues and other operating assets	75,966	53,511
Accounts payable and other operating liabilities	(5,255)	(14,307)
Regulatory assets - current	27,768	(43,727)
Regulatory liabilities - current	2,457	(9,845)
Contributions to defined benefit pension plans	(10,200)	(10,200)
Other operating activities, net	(6,403)	4,087
Net cash provided by (used in) operating activities	365,873	239,157
Investing activities:		
Property, plant and equipment additions	(349,471)	(290,299)
Proceeds from sale of assets	—	22,342
Other investing activities	(7,189)	(2,364)
Net cash provided by (used in) investing activities	(356,660)	(270,321)
Financing activities:		
Dividends paid on common stock	(54,450)	(52,218)
Common stock issued	2,484	2,393
Short-term borrowings - issuances	287,910	396,250
Short-term borrowings - repayments	(245,010)	(294,750)
Long-term debt - issuances	300,000	—
Long-term debt - repayments	(275,000)	(12,200)
Other financing activities	(7,524)	(4,213)
Net cash provided by (used in) financing activities	8,410	35,262
Net change in cash and cash equivalents	17,623	4,098
Cash and cash equivalents, beginning of period	21,218	7,841
Cash and cash equivalents, end of period	$38,841	$11,939

See Note 14 for supplemental disclosure of cash flow information.

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

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BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2014 Annual Report on Form 10-K/A)

(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 2014 Annual Report on Form 10-K/A filed with the SEC.

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Coal Mining and Oil and Gas. Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2015, December 31, 2014, and September 30, 2014 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2015 and September 30, 2014, and our financial condition as of September 30, 2015, December 31, 2014, and September 30, 2014, 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.

Recently Issued and Adopted Accounting Standards

We have implemented all new accounting pronouncements that are in effect and may impact our financial statements. We are currently assessing the impact any other new accounting pronouncements that have been issued may have on our financial position, results of operations, or cash flows.

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. Early adoption is permitted. We are currently evaluating the impact of adoption that ASU

2015-03 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, 2018 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.

Correction of Immaterial Errors

In preparing our condensed consolidated financial statements for the quarter ended June 30, 2015, we identified immaterial errors that impacted our previously issued consolidated financial statements. The prior period errors originated in the year ended December 31, 2008 and related to our oil and gas full cost ceiling impairment calculation to determine whether the net book value of our oil and gas properties exceeded the ceiling. Specifically, the errors related to evaluating and correctly accounting for the treatment of tax-related amounts associated with the calculation. The errors identified caused an understatement of 2008, 2009, 2012 and Q1 2015 non-cash ceiling test impairment calculations, which resulted in an overstatement of depletion expense from 2009 through March 31, 2015, and an understatement of the 2012 gain on sale of oil and gas properties.
In accordance with Staff Accounting Bulletin (SAB) No. 99, Materiality, and SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, we evaluated these errors, including both qualitative and quantitative considerations, and concluded that the errors did not, individually or in the aggregate, result in a material misstatement of our previously issued condensed consolidated financial statements.

The following tables present the revisions to particular line items resulting from the corrections of these errors in this Quarterly Report on Form 10-Q. The impact of the errors relate entirely to our Oil and Gas segment.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	For the Three Months Ended September 30, 2014			For the Nine Months Ended September 30, 2014		
	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
	(in thousands, expect per share amounts)					
Depreciation, depletion and amortization	$37,463	$(835)	$36,628	$110,258	$(2,504)	$107,754
Total operating expenses	$217,683	$(835)	$216,848	$824,914	$(2,504)	$822,410
Operating income (loss)	$54,404	$835	$55,239	$190,579	$2,504	$193,083
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	$38,168	$835	$39,003	$142,124	$2,504	$144,628
Income tax benefit (expense)	$(11,332)	$(308)	$(11,640)	$(47,349)	$(923)	$(48,272)
Net income (loss) available for common stock	$26,836	$527	$27,363	$94,774	$1,581	$96,355

Earnings (loss) per share of common stock:						
Earnings (loss) per share, Basic	$0.60	$0.02	$0.62	$2.14	$0.03	$2.17
Earnings (loss) per share, Diluted	$0.60	$0.01	$0.61	$2.13	$0.03	$2.16

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the Three Months Ended September 30, 2014			For the Nine Months Ended September 30, 2014		
(in thousands)	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
Net income (loss) available for common stock	$26,836	$527	$27,363	$94,774	$1,581	$96,355
Comprehensive income (loss)	$31,438	$527	$31,965	$97,357	$1,581	$98,938

CONDENSED CONSOLIDATED BALANCE SHEETS

	As of September 30, 2014		
	As Reported	Adjustments	As Revised
	(in thousands)		
Accumulated depreciation and depletion	$(1,338,509)	$(34,738)	$(1,373,247)
Total property, plant and equipment, net	$3,155,187	$(34,738)	$3,120,449
TOTAL ASSETS	$4,073,262	$(34,738)	$4,038,524
Deferred income tax liability, non-current	$506,166	$(12,071)	$494,095
Total deferred credits and other liabilities	$881,308	$(12,071)	$869,237
Retained earnings	$582,800	$(22,667)	$560,133
Total stockholders' equity	$1,357,392	$(22,667)	$1,334,725
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,073,262	$(34,738)	$4,038,524

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2014		
	As Reported	Adjustments	As Revised
	(in thousands)		
Net income (loss) available for common stock	$94,774	$1,581	$96,355
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	$110,258	$(2,504)	$107,754
Deferred income taxes	$48,007	$923	$48,930
Net cash provided by (used in) operating activities	$239,157	$—	$239,157

The Notes to the Condensed Consolidated Financial Statements have been revised to reflect the correction of these errors for all periods presented.

(2) ACQUISITION

Acquisition of SourceGas

On July 12, 2015, Black Hills Utility Holdings entered into a definitive agreement to acquire SourceGas Holdings LLC and its subsidiaries from investment funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE), for approximately $1.89 billion, which includes $200 million of projected capital expenditures through closing and the assumption of $700 million in debt projected at closing. The effective purchase price is estimated to be $1.74 billion after taking into account approximately $150 million of future tax benefits associated with acquired NOLs and the step up in certain assets including goodwill resulting from the transaction. The purchase price is subject to customary post-closing adjustments for cash, capital expenditures, indebtedness and working capital. In conjunction with the agreement, we entered into a commitment letter for a one-year, $1.17 billion senior unsecured fully-committed bridge facility provided by Credit Suisse, subsequently replaced on August 6, 2015 by the Bridge Term Loan Agreement discussed below.

We expect to finance the acquisition with equity proceeds of $450 million to $600 million, including $200 million to $300 million of unit mandatory convertibles, $450 million to $550 million of new long-term indebtedness, and assuming approximately $700 million of continuing debt of SourceGas, with the remainder funded from cash on hand and draws under our revolving credit agreement.

SourceGas primarily operates four regulated natural gas utilities serving approximately 425,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. Following completion of the transaction, SourceGas will be a wholly-owned subsidiary of Black Hills Utility Holdings.

The agreement for the acquisition of SourceGas is subject to various provisions including representations, warranties, and covenants with respect to Arkansas, Colorado, Nebraska and Wyoming utility businesses that are subject to customary conditions and limitations. Completion of the transaction is also subject to regulatory approvals from the APSC, CPUC, NPSC and WPSC, and was also subject to notification, clearance and reporting requirements under the Hart-Scott-Rodino Act, which waiting period expired on August 18, 2015. On August 10, 2015, we filed joint applications with the APSC, CPUC, NPSC and WPSC, requesting a March 1, 2016 approval date in all four filings. The discovery process with all four state commissions is ongoing and the acquisition is expected to close during the first half of 2016.

BHC has guaranteed the full and complete payment and performance of Black Hills Utility Holdings.

Effective August 6, 2015, we entered into a Bridge Term Loan Agreement with Credit Suisse as the Administrative Agent and 10 additional banks, collectively, for commitments totaling $1.17 billion pursuant to the previously executed bridge commitment letter with Credit Suisse. We may draw up to $1.17 billion on this loan to fund the SourceGas Acquisition and related expenses. The Agreement contains the same customary affirmative and negative covenants as contained in our Revolving Credit Agreement and Term Loan Credit Agreement, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and maintaining a recourse leverage ratio not to exceed 0.75 to 1. In the event we fund under the Bridge Term Loan Agreement, in certain circumstances, we are required to pay down those borrowings with funds received from the proceeds of equity and debt offerings and asset sales. Additionally, our Revolving Credit Facility and Term Loan Credit Agreements were amended in connection with the Bridge Term Loan Agreement to permit the assumption of certain indebtedness of SourceGas and to increase the Recourse Leverage Ratio in certain circumstances. In these amendments, the maximum Recourse Ratio is no greater than 0.65 to 1 at the end of any fiscal quarter, but may increase to (i) 0.70 to 1 at the end of any fiscal quarter during such four fiscal quarter period where the aggregate outstanding debt assumed or incurred in connection with our acquisition of SourceGas is equal to or greater than $1.25 billion and less than $1.46 billion or (ii) 0.75 to 1 at the end of any fiscal quarter during such four fiscal quarter period that the aggregate outstanding debt assumed or incurred in connection with our acquisition of SourceGas is equal to or greater than $1.46 billion.

(3) BUSINESS SEGMENT INFORMATION

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

Three Months Ended September 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$182,263	$2,547	$21,982
Gas	68,934	—	1,630
Non-regulated Energy:			
Power Generation	2,123	21,128	9,067
Coal Mining	8,890	8,076	3,047
Oil and Gas [(a)]	9,895	—	(39,769)
Corporate activities [(c)]	—	—	(5,900)
Inter-company eliminations	—	(31,751)	—
Total	$272,105	$—	$(9,943)

Three Months Ended September 30, 2014	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$171,395	$3,156	$18,154
Gas	78,735	—	1,597
Non-regulated Energy:			
Power Generation	1,602	20,419	7,829
Coal Mining	6,884	8,689	2,638
Oil and Gas	13,471	—	(2,583)
Corporate activities	—	—	(272)
Inter-company eliminations	—	(32,264)	—
Total	$272,087	$—	$27,363

Nine Months Ended September 30, 2015	External Operating Revenues	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$534,988	$8,480	$58,613
Gas	386,011	—	27,007
Non-regulated Energy:			
Power Generation	5,782	62,452	24,761
Coal Mining	26,084	23,541	9,106
Oil and Gas [(a)(b)]	33,481	—	(130,079)
Corporate activities [(c)]	—	—	(7,343)
Inter-company eliminations	—	(94,473)	—
Total	$986,346	$—	$(17,935)

Nine Months Ended September 30, 2014	External Operating Revenues	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$508,230	$10,307	$44,156
Gas	440,571	—	28,289
Non-regulated Energy:			
Power Generation	4,138	62,211	23,096
Coal Mining	19,085	26,637	7,118
Oil and Gas	43,469	—	(5,211)
Corporate activities	—	—	(1,093)
Inter-company eliminations	—	(99,155)	—
Total	$1,015,493	$—	$96,355

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(a) Net income (loss) for the three and nine months ended September 30, 2015 included non-cash after-tax ceiling test impairments of $36 million and $113 million, respectively. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) for the nine months ended September 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

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

Total Assets (net of inter-company eliminations) as of:	September 30, 2015	December 31, 2014	September 30, 2014
Utilities:			
Electric [(a)]	$2,846,931	$2,748,680	$2,671,601
Gas	831,802	906,922	827,069
Non-regulated Energy:			
Power Generation [(a)]	78,666	76,945	64,359
Coal Mining	78,000	74,407	74,130
Oil and Gas [(b)] [(c)]	280,842	332,343	296,043
Corporate activities	130,321	106,605	105,322
Total assets	$4,246,562	$4,245,902	$4,038,524

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(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation Station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

(b) As a result of continued low commodity prices during 2015, we recorded non-cash impairments of oil and gas assets included in our Oil and Gas segment of $62 million and $178 million for the for the three and nine months ended September 30, 2015, respectively. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(c) Includes a non-cash impairment of our Oil and Gas equity investments of $5.2 million for the nine months ended September 30, 2015. See Note 17 to the Condensed Consolidated Financial Statements in this Quarterly Report on

Form 10-Q.

(4) ACCOUNTS RECEIVABLE

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

September 30, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$43,337	$35,069	$(720)	$77,686
Gas Utilities	18,349	10,140	(618)	27,871
Power Generation	1,186	—	—	1,186
Coal Mining	2,684	—	—	2,684
Oil and Gas	4,522	—	(13)	4,509
Corporate	1,566	—	—	1,566
Total	$71,644	$45,209	$(1,351)	$115,502

December 31, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$59,714	$26,474	$(722)	$85,466
Gas Utilities	47,394	45,546	(781)	92,159
Power Generation	1,369	—	—	1,369
Coal Mining	3,151	—	—	3,151
Oil and Gas	5,305	—	(13)	5,292
Corporate	2,555	—	—	2,555
Total	$119,488	$72,020	$(1,516)	$189,992

September 30, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$53,717	$21,485	$(724)	$74,478
Gas Utilities	23,409	13,218	(740)	35,887
Power Generation	1,368	—	—	1,368
Coal Mining	2,563	—	—	2,563
Oil and Gas	7,657	—	(13)	7,644
Corporate	1,459	—	—	1,459
Total	$90,173	$34,703	$(1,477)	$123,399

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of September 30, 2015	As of December 31, 2014	As of September 30, 2014
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)] [(d)]	1	$25,354	$23,820	$26,211
Deferred gas cost adjustments [(a)(d)]	2	9,358	37,471	42,400
Gas price derivatives [(a)]	7	23,681	18,740	7,470
AFUDC [(b)]	45	12,580	12,358	12,411
Employee benefit plans [(c)] [(e)]	12	95,779	97,126	64,908
Environmental [(a)]	subject to approval	1,209	1,314	1,314
Asset retirement obligations [(a)]	44	675	3,287	3,282
Bond issue cost [(a)]	23	3,169	3,276	3,311
Renewable energy standard adjustment [(b)]	5	5,102	9,622	12,007
Flow through accounting [(c)]	35	28,585	25,887	25,157
Decommissioning costs [(f)]	10	16,353	12,484	—
Other regulatory assets [(a)]	15	12,454	12,454	10,395
		$234,299	$257,839	$208,866
Regulatory liabilities				
Deferred energy and gas costs [(a)] [(d)]	1	$9,899	$6,496	$5,535
Employee benefit plans [(c)] [(e)]	12	53,140	53,139	34,409
Cost of removal [(a)]	44	86,946	78,249	71,362
Other regulatory liabilities [(c)]	25	7,826	10,947	8,378
		$157,811	$148,831	$119,684

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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. Fluctuations in deferred gas cost adjustments compared to the same period in the prior year are primarily due to higher natural gas prices driven by demand and market conditions from the peak winter heating season in the first part of 2014. 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 September 30, 2014 was driven by a decrease in the discount rate and a change in the mortality tables used in employee benefit plan estimates.

(f) Black Hills Power 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.

(6) MATERIALS, SUPPLIES AND FUEL

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

	September 30, 2015	December 31, 2014	September 30, 2014
Materials and supplies	$53,838	$49,555	$52,682
Fuel - Electric Utilities	6,139	6,637	7,108
Natural gas in storage held for distribution	30,372	34,999	45,936
Total materials, supplies and fuel	$90,349	$91,191	$105,726

(7) GOODWILL

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

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2014	$250,487	$94,144	$8,765	$353,396
Additions [(a)]	6,131	—	—	6,131
Ending balance at September 30, 2015	$256,618	$94,144	$8,765	$359,527

(a) Goodwill was recorded on the acquisition of Wyoming natural gas utility Energy West Wyoming, Inc., and natural gas pipeline assets from Energy West Development, Inc. completed on July 1, 2015.

(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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss) available for common stock	$(9,943)	$27,363	$(17,935)	$96,355
Weighted average shares - basic	44,635	44,415	44,598	44,382
Dilutive effect of:				
Equity compensation	—	193	—	202
Weighted average shares - diluted	44,635	44,608	44,598	44,584

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

In addition to these potentially dilutive shares excluded due to our net loss for the three and nine months ended September 30, 2015, the following outstanding securities were also excluded in the computation of diluted net income (loss) per share as their inclusion would have been anti-dilutive (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Equity compensation	121	99	114	75
Anti-dilutive shares	121	99	114	75

(9) NOTES PAYABLE AND LONG-TERM DEBT

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

	September 30, 2015		December 31, 2014		September 30, 2014	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$117,900	$30,600	$75,000	$35,000	$184,000	$31,726

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, at September 30, 2015. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating.

Replacement of Corporate Term Loan

On April 13, 2015, we entered into a new $300 million Corporate term loan expiring April 12, 2017. This new term loan replaced the $275 million Corporate term loan due on June 19, 2015 and was classified as Long-Term Debt as of September 30, 2015. The additional $25 million, less interest and fees, was used for general corporate purposes. The cost of the borrowing under the new term loan is LIBOR plus a margin of 0.9%. The covenants on the new term loan are substantially the same as the Revolving Credit Facility.

Debt Covenants

On August 6, 2015, in connection with the Bridge Term Loan Agreement as 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 in certain circumstances. In these amendments, the maximum Recourse Ratio is no greater than 0.65 to 1 at the end of any fiscal quarter, but may increase to (i) 0.70 to 1 at the end of any fiscal quarter during such four fiscal quarter period where the aggregate outstanding debt assumed or incurred in connection with our acquisition of SourceGas is equal to or greater than $1.25 billion and less than $1.46 billion or (ii) 0.75 to 1 at the end of any fiscal quarter during such four fiscal quarter period that the aggregate outstanding debt assumed or incurred in connection with our acquisition of SourceGas is equal to or greater than $1.46 billion.

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

	As of September 30, 2015	Covenant Requirement
Recourse Leverage Ratio	58%	Less than 65%

As of September 30, 2015, we were in compliance with this covenant.

(10) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2014 Annual Report on Form 10-K/A.

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.

Credit Risk

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

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

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

Our 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 11.

Oil and Gas

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

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures 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:

	September 30, 2015		December 31, 2014		September 30, 2014	
	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)]	258,000	5,392,500	334,500	6,582,500	391,500	7,930,000
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 September 30, 2015 prices, an $8.8 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 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. 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).

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our Utilities were as follows, as of:

	September 30, 2015		December 31, 2014		September 30, 2014	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	17,180,000	63	19,370,000	72	16,290,000	74
Natural gas options purchased	6,300,000	6	4,020,000	8	7,070,000	6
Natural gas basis swaps purchased	12,980,000	51	12,005,000	60	12,025,000	63

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(a) Term reflects the maximum forward period hedged.

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

	September 30, 2015	December 31, 2014	September 30, 2014
Derivative assets, current	$—	$—	$—
Derivative assets, non-current	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$23,678	$18,740	$7,470

Financing Activities

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

	September 30, 2015	December 31, 2014	September 30, 2014
	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]
Notional	$75,000	$75,000	$75,000
Weighted average fixed interest rate	4.97 %	4.97 %	4.97 %
Maximum terms in years	1.33	2.00	2.25
Derivative liabilities, current	$3,312	$3,340	$3,397
Derivative liabilities, non-current	$722	$2,680	$3,273

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

Based on September 30, 2015 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.3 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 September 30, 2015

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

Three Months Ended September 30, 2014

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$152	Interest expense	$(925)		$—
Commodity derivatives	4,833	Revenue	(1,135)		—
Total	$4,985		$(2,060)		$—

Nine Months Ended September 30, 2015

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

Nine Months Ended September 30, 2014

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$(277)	Interest expense	$(2,745)		$—
Commodity derivatives	(1,376)	Revenue	(2,697)		—
Total	$(1,653)		$(5,442)		$—

(11) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information see Notes 1, 8, 9 and 10 to the Consolidated Financial Statements included in our 2014 Annual Report on Form 10-K/A 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 and basis swaps (Level 2) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the exchange settlement pricing for the applicable contract.

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 our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

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 our gross assets and gross liabilities and related offsetting cash collateral and counterparty netting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

	As of September 30, 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	—	6,642	—	(6,642)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	4,622	—	(4,622)	—
Commodity derivatives — Utilities	—	3,123	—	(3,123)	—
Total	$—	$14,387	$—	$(14,387)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	467	—	(467)	—
Commodity derivatives — Utilities	—	24,445	—	(24,445)	—
Interest rate swaps	—	4,034	—	—	4,034
Total	$—	$28,946	$—	$(24,912)	$4,034

	As of December 31, 2014				
	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	—	8,599	—	(8,599)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	6,558	—	(6,558)	—
Commodity derivatives —Utilities	—	2,389	—	(2,389)	—
Total	$—	$17,546	$—	$(17,546)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	473	—	(473)	—
Commodity derivatives — Utilities	—	19,303	—	(19,303)	—

Interest rate swaps	—	6,020	—	—	6,020
Total	$—	$25,796	$—	$(19,776)	$6,020

	As of September 30, 2014				
	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	—	322	—	(322)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,545	—	(1,545)	—
Commodity derivatives — Utilities	—	4,029	—	(4,029)	—
Total	$—	$5,896	$—	$(5,896)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	487	—	(487)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	865	—	(865)	—
Commodity derivatives — Utilities	—	8,679	—	(8,679)	—
Interest rate swaps	—	6,670	—	—	6,670
Total	$—	$16,701	$—	$(10,031)	$6,670

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 September 30, 2015, December 31, 2014, and September 30, 2014, 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 10.

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

As of September 30, 2015

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

As of December 31, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$10,391	$—
Commodity derivatives	Derivative assets — non-current	4,766	—
Commodity derivatives	Derivative liabilities — current	—	185
Commodity derivatives	Derivative liabilities — non-current	—	288
Interest rate swaps	Derivative liabilities — current	—	3,340
Interest rate swaps	Derivative liabilities — non-current	—	2,680
Total derivatives designated as hedges		$15,157	$6,493
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	8,032
Commodity derivatives	Derivative liabilities — non-current	—	8,882
Total derivatives not designated as hedges		$—	$16,914

As of September 30, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,174	$—
Commodity derivatives	Derivative assets — non-current	692	—
Commodity derivatives	Derivative liabilities — current	—	497
Commodity derivatives	Derivative liabilities — non-current	—	856
Interest rate swaps	Derivative liabilities — current	—	3,397
Interest rate swaps	Derivative liabilities — non-current	—	3,273
Total derivatives designated as hedges		$1,866	$8,023
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	48
Commodity derivatives	Derivative liabilities — non-current	—	4,602
Total derivatives not designated as hedges		$—	$4,650

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	September 30, 2015		December 31, 2014		September 30, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$38,841	$38,841	$21,218	$21,218	$11,939	$11,939
Restricted cash and equivalents [(a)]	$2,462	$2,462	$2,056	$2,056	$1,918	$1,918
Notes payable [(a)]	$117,900	$117,900	$75,000	$75,000	$184,000	$184,000
Long-term debt, including current maturities [(b)]	$1,567,797	$1,718,964	$1,542,589	$1,734,555	$1,382,519	$1,547,359

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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.

(13) OTHER COMPREHENSIVE INCOME (LOSS)

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

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI			
		Three Months Ended		Nine Months Ended	
		September 30, 2015	September 30, 2014	September 30, 2015	September 30, 2014
Gains (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$1,603	$925	$4,709	$2,745
Commodity contracts	Revenue	(3,109)	1,135	(10,707)	2,697
		(1,506)	2,060	(5,998)	5,442
Income tax	Income tax benefit (expense)	558	(732)	2,548	(1,931)
Reclassification adjustments related to cash flow hedges, net of tax		$(948)	$1,328	$(3,450)	$3,511
Amortization of defined benefit plans:					
Prior service cost	Utilities - Operations and maintenance	$(26)	$(26)	$(80)	$(77)
	Non-regulated energy operations and maintenance	(29)	(22)	(86)	(93)
Actuarial gain (loss)	Utilities - Operations and maintenance	454	158	1,362	473

	Non-regulated energy operations and maintenance	252	88	754	274
		651	198	1,950	577
Income tax	Income tax benefit (expense)	(228)	(69)	(684)	(202)
Reclassification adjustments related to defined benefit plans, net of tax		$423	$129	$1,266	$375

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, 2013	$(7,133)	$(10,289)	$(17,422)
Other comprehensive income (loss), net of tax	(1,478)	311	(1,167)
Balance as of March 31, 2014	(8,611)	(9,978)	(18,589)
Other comprehensive income (loss), net of tax	(556)	(296)	(852)
Balance as of June 30, 2014	(9,167)	(10,274)	(19,441)
Other comprehensive income (loss), net of tax	4,473	129	4,602
Ending Balance September 30, 2014	$(4,694)	$(10,145)	$(14,839)
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)
Other comprehensive income (loss), net of tax	422	(3,227)	(2,805)
Balance as of June 30, 2015	6,110	(22,969)	(16,859)
Other comprehensive income (loss), net of tax	1,825	423	2,248
Ending Balance September 30, 2015	$7,935	$(22,546)	$(14,611)

(14) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine months ended	September 30, 2015	September 30, 2014
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$52,314	$52,484
Increase (decrease) in capitalized assets associated with asset retirement obligations	$—	$(2,785)
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(49,797)	$(46,086)
Income taxes, net	$(1,202)	$(396)

(15) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Service cost	$1,494	$1,362	$4,482	$4,086
Interest cost	3,880	3,963	11,640	11,889
Expected return on plan assets	(4,867)	(4,516)	(14,601)	(13,549)
Prior service cost	15	16	45	47
Net loss (gain)	2,759	1,201	8,277	3,604
Net periodic benefit cost	$3,281	$2,026	$9,843	$6,077

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Defined Benefit Postretirement Healthcare Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Service cost	$464	$425	$1,392	$1,275
Interest cost	450	480	1,350	1,439
Expected return on plan assets	(33)	(21)	(99)	(64)
Prior service cost (benefit)	(107)	(107)	(321)	(321)
Net loss (gain)	102	40	306	120
Net periodic benefit cost	$876	$817	$2,628	$2,449

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Service cost	$(84)	$374	$799	$1,123
Interest cost	364	362	1,092	1,085
Prior service cost	1	1	3	2
Net loss (gain)	270	124	810	373
Net periodic benefit cost	$551	$861	$2,704	$2,583

Contributions

We anticipate that we will make contributions to the benefit plans in 2015 and 2016. Contributions to the Defined Benefit Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Contributions to the Healthcare and Supplemental Plan are made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

	Contributions Made	Contributions Made	Additional Contributions	Contributions
	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015	Anticipated for 2015	Anticipated for 2016
Defined Benefit Pension Plans	$10,200	$10,200	$—	$10,200
Non-pension Defined Benefit Postretirement Healthcare Plans	$939	$2,817	$939	$4,026
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$372	$1,116	$372	$1,544

(16) 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 2014 Annual Report on Form 10-K/A except for those described below and in Note 2 and in Note 19.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A fire investigator retained by the Weston County Fire Protection District concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power. On April 16, 2013, a large group of private landowners filed suit in the United States District Court for the District of Wyoming. There are approximately 36 Plaintiff groups (including property jointly owned by multiple family members or entities), or approximately 73 individually named private plaintiffs. In addition, the State of Wyoming intervened in the lawsuit. These parties asserted claims seeking recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate. On September 30, 2015, we agreed to a settlement with the State of Wyoming. The settlement amount is not material to the Company. We have recorded a corresponding receivable as we believe our settlement costs are reimbursable and probable of recovery under our insurance coverage. A trial for the private landowners' suit has been scheduled to commence in February 2016.

The private landowners' claims for damages against Black Hills Power include allegations of negligence, negligence per se, common law nuisance and trespass. In addition to claims for compensatory damages, the lawsuit sought recovery of punitive damages; however, in October 2015, the court dismissed the claim for punitive damages. At that time, the court also ruled on a motion regarding the measure of damages to be applied to this matter. Based on that standard, we estimate the current total private claims to be approximately $55 million; however, the actual amount of allowed claims and any loss will depend on the resolution of certain factual and legal issues. We have denied and continue to vigorously defend these claims. However, civil litigation of this kind is likely to lead to settlement negotiations, including negotiations prompted by pre-trial civil court procedures. We believe such negotiations would effect a settlement of all claims. Regardless of whether the litigation is determined at trial or through settlement, we expect to incur significant investigation, legal and expert services expenses associated with the litigation. We maintain insurance coverage to limit our exposure to losses due to civil liability claims, and related litigation expense, and we will pursue recoveries to the maximum extent available under the policies. The deductible applicable to some types of claims arising out of this fire is $1.0 million. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, we recorded a loss contingency liability related to these claims and we recorded a receivable for costs we believe are reimbursable and probable of recovery under our insurance coverage. Both of these entries reflect our reasonable estimate of probable future litigation expense and settlement costs; we did not base these contingencies on any determination that it is probable we would be found liable for these claims were they to be litigated.

Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims in excess of the loss we have determined to be probable is reasonably possible. We cannot reasonably estimate the amount of such possible loss because our review of damage claim documentation and related expert opinions is ongoing, and there are significant factual and legal issues to be resolved relating to potential damage claims. Further claims may be presented by other parties. We are not yet able to reasonably estimate the amount of any reasonable possible losses in excess of the amount we have accrued. Based upon information currently available, however, management does not expect the outcome of the claims to have a material adverse effect upon our consolidated financial condition, results of operations or cash flows.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of September 30, 2015, we were in compliance with the debt covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at September 30, 2015:

- 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. As of September 30, 2015, the restricted net assets at our Utilities Group were approximately $334 million.

(17) IMPAIRMENT OF ASSETS

Long-lived assets

Our Oil and Gas segment accounts for oil and gas activities under the full cost method of accounting. Under the full cost method, all productive and non-productive costs related to acquisition, exploration, development, abandonment and reclamation activities are capitalized. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties. Any costs in excess of the ceiling are written off as a non-cash charge.

As a result of continued low commodity prices throughout 2015, we have recorded the following non-cash impairments of our oil and gas assets included in our Oil and Gas segment. 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.

- 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.

- During the second quarter of 2015, we recorded a $94 million pre-tax non-cash impairment of oil and gas assets. For natural gas, the average NYMEX price was $3.39 per Mcf, adjusted to $2.14 per Mcf at the wellhead; for crude oil, the average NYMEX price was $71.68 per barrel, adjusted to $63.76 per barrel at the wellhead.

- During the third quarter of 2015, we recorded a $62 million pre-tax non-cash impairment of oil and gas assets. For natural gas, the average NYMEX price was $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead; for crude oil, the average NYMEX price was $59.21 per barrel, adjusted to $52.82 per barrel at the wellhead.

Equity investments in unconsolidated subsidiaries

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

(18) INCOME TAXES

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

	Three Months Ended September 30,	
Tax (benefit) expense	2015	2014
Federal statutory rate	(35.0)%	35.0 %
State income tax (net of federal tax effect)	(4.7)	(0.2)
Percentage depletion in excess of cost	(2.0)	(1.3)
Accounting for uncertain tax positions adjustment	1.2	(2.9)
Flow-through adjustments	(2.4)	(1.7)
Inter-period tax allocation	(11.2)	1.6
Other tax differences	(0.7)	(0.7)
	(54.8)%	29.8 %

	Nine Months Ended September 30,	
Tax (benefit) expense	2015	2014
Federal statutory rate	(35.0)%	35.0 %
State income tax (net of federal tax effect)	(6.7)	0.7
Percentage depletion in excess of cost	(4.5)	(1.0)
Accounting for uncertain tax positions adjustment	4.7	(0.4)
Flow-through adjustments	(4.7)	(1.1)
Other tax differences	1.3	0.1
	(44.9)%	33.3 %

The change in our effective tax rates is primarily due to the state income tax benefit resulting from the non-cash impairments of the oil and gas properties, and the favorable impact of percentage depletion particularly at our coal mine.

(19) SUBSEQUENT EVENT

Build Transfer Agreement

On November 2, 2015, Black Hills 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 is expected to start in the spring of 2016, and be completed in late 2016. Under the build transfer agreement, Black Hills Colorado Electric will make progress payments starting in late 2015, continuing through completion of the project. Ownership of Peak View will transfer prior to commercial operation to Black Hills Colorado Electric and will be operated as a utility-owned asset. BHC has guaranteed the full and complete payment and performance on behalf of Black Hills Colorado Electric.

Interest Rate Swap Lock

On October 2, 2015, we executed a 10 year, $250 million notional, 2.29% swap lock to hedge the risks of interest rate movement between the hedge date and the expected pricing date for our anticipated long-term debt financing. The swap will be accounted for as a cash flow hedge and any gain or loss will be recorded in Accumulated Other Comprehensive Income (loss). The forward-starting interest rate swap can be used to lock-in interest rates on future debt issuances we anticipate completing in 2016. The swap has a mandatory termination date of April 12, 2027.

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

We are a utility-centered, growth-oriented, vertically-integrated energy company operating principally in the United States with two major business groups — Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Power Generation
	Coal Mining
	Oil and Gas

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 205,400 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 44,000 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 543,200 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Power Generation, Coal Mining and Oil and Gas segments. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities. Our Oil and Gas segment engages in exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for our electric utilities is June through August while the normal peak usage season for our gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2015 and 2014, and our financial condition as of September 30, 2015, December 31, 2014 and September 30, 2014, 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.

Transition Oil and Gas business to support cost of service gas initiative while maintaining upside value optionality

On September 30, 2015, our 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, Black Hills will acquire natural gas reserves and/or drill wells to produce natural gas for the program.

Our strategy is to transition our Oil and Gas business toward supporting our Cost of Service Gas Program and similar programs in partnership with other utilities, while maintaining the upside value optionality of our Piceance Basin and other assets. In the current low energy commodity price environment, we can best utilize our oil and gas expertise to develop and operate the Cost of Service Gas Program on behalf of our utility businesses and similar programs in partnership with third-party utilities. Our oil and gas strategy for the last several years has been to prove up the

southern Piceance Basin asset, while improving our drilling and completion operations. We have drilled 17 wells and completed 13, with production meeting or exceeding our expectations on the completed wells. Drilling and completion costs have trended down as we focus on efficiencies and cost reductions. Sustained low oil and natural gas prices have also resulted in reduced costs for drilling and completion services, equipment and materials. We are currently assessing the Piceance wells to determine their fit for a Cost of Service Gas Program.
See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 67.

The following business group and 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.

Certain disclosures included in this Management Discussion and Analysis have been revised as discussed in the Note 1 of the Condensed Consolidated Financial Statements included in this Quarterly Report on Form 10-Q.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. Net income (loss) for the three months ended September 30, 2015 was $(10) million, or $(0.22) per share, compared to Net income (loss) of $27 million, or $0.61 per share, reported for the same period in 2014. The Net income (loss) for the three months ended September 30, 2015 included a non-cash after-tax ceiling test impairment of $36 million. The Net income (loss) for the three months ended September 30, 2014 did not contain any expenses, gains or losses that we believe are not representative of our core operating performance.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. Net income (loss) for the nine months ended September 30, 2015 was $(18) million, or $(0.40) per share, compared to Net income (loss) of $96 million, or $2.16 per share, reported for the same period in 2014. The Net income (loss) for the nine months ended September 30, 2015 included a non-cash after-tax ceiling test impairment of $113 million and a non-cash after-tax impairment loss on an equity investment of $3.4 million. The Net income (loss) for the nine months ended September 30, 2014 did not contain any expenses, gains or losses that we believe are not representative of our core operating performance.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
Revenue						
Utilities	$253,744	$253,286	$458	$929,479	$959,108	$(29,629)
Non-regulated Energy	50,112	51,065	(953)	151,340	155,540	(4,200)
Inter-company eliminations	(31,751)	(32,264)	513	(94,473)	(99,155)	4,682
	$272,105	$272,087	$18	$986,346	$1,015,493	$(29,147)
Net income (loss)						
Electric Utilities	$21,982	$18,154	$3,828	$58,613	$44,156	$14,457
Gas Utilities	1,630	1,597	33	27,007	28,289	(1,282)
Utilities	23,612	19,751	3,861	85,620	72,445	13,175
Power Generation	9,067	7,829	1,238	24,761	23,096	1,665
Coal Mining	3,047	2,638	409	9,106	7,118	1,988
Oil and Gas [(a)] [(b)]	(39,769)	(2,583)	(37,186)	(130,079)	(5,211)	(124,868)
Non-regulated Energy	(27,655)	7,884	(35,539)	(96,212)	25,003	(121,215)
Corporate activities and eliminations [(c)]	(5,900)	(272)	(5,628)	(7,343)	(1,093)	(6,250)
Net income (loss)	$(9,943)	$27,363	$(37,306)	$(17,935)	$96,355	$(114,290)

(a) Net income (loss) for the three and nine months ended September 30, 2015 included non-cash after-tax ceiling test impairments of $36 million and $113 million, respectively. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b)

Net income (loss) for the nine months ended September 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

Overview of Business Segments and Corporate Activity

Utilities Group

- On September 30, 2015, our 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, Black Hills will acquire natural gas reserves and/or drill wells to produce natural gas for the program. Based on historical performance, the cost of production is expected to be more stable and predictable than the spot market price of natural gas.

- Electric Utilities experienced warmer weather during the three months ended September 30, 2015, compared to the same period in the prior year. Cooling degree days were 36% higher than the same period in the prior year, and 19% higher than normal. This increase in cooling degree days during the third quarter of 2015 offset the effects of milder weather in our service territories earlier in the year.

- Gas Utilities experienced milder weather during the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014. Heating degree days were 61% and 11% lower, respectively, for the three and nine months ended September 30, 2015, compared to the same periods in 2014. Heating degree days for the three and nine months ended September 30, 2015 were 57% lower and 1% lower than normal, respectively, compared to 6% and 12% higher than normal for the same periods in 2014.

- Construction on Colorado Electric's $65 million 40 MW natural gas-fired combustion turbine continued in the third quarter of 2015. Through September 30, 2015, approximately $27 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 $0.6 million and $1.3 million, respectively, for the three and nine months ended September 30, 2015.

- On July 23, 2015, Black Hills Power received approval from the WPSC for a CPCN originally filed on July 22, 2014 to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. Black Hills Power received approval on November 6, 2014 from the SDPUC for a permit to construct the South Dakota portion of this line. Black Hills Power plans to commence construction in the fourth quarter of 2015.

- On July 1, 2015, we completed the acquisition of Wyoming natural gas utility Energy West Wyoming, Inc., and natural gas pipeline assets from Energy West Development, Inc. The utility and pipeline assets were acquired for approximately $17 million, and will operate under Cheyenne Light. The acquired system serves approximately 6,700 customers, in Cody, Ralston, and Meeteetse, Wyoming. The pipeline acquisition includes a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory.

- On June 23, 2015, Colorado Electric filed for a CPCN with the CPUC to acquire the planned 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 will be built by Invenergy Wind Development Colorado LLC and is expected to be completed in the fourth quarter of 2016. On September 24, 2015, Colorado Electric filed an uncontested Settlement Agreement that would approve the build transfer proposal. 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 would 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. The Commission determined it did not need to hold a hearing regarding the settlement and considered and approved the project on October 21, 2015. We expect a written order formally approving the project in November 2015. Assuming CPUC formal approval, Colorado Electric will purchase the project for approximately $109 million through progress payments throughout 2016, with ownership transfer occurring just before achieving commercial operation.

- On March 16, 2015, we announced plans to build a new corporate headquarters in Rapid City that will consolidate our approximately 500 employees in Rapid City from five locations into one. The investment in the new corporate headquarters will be approximately $70 million and will support all our businesses. The cost of the facility will replace existing expenses associated with our current facilities throughout Rapid City. Construction began in September 2015 with completion expected in 2017.

- On March 2, 2015, the SDPUC issued an order approving a rate stipulation and agreement authorizing an annual electric revenue increase for Black Hills Power of $6.9 million. The agreement was a Global Settlement and did not stipulate return on equity and capital structure. The SDPUC's decision provides Black Hills Power a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for this natural gas-fired facility. Black Hills Power implemented interim rates on October 1, 2014, coinciding with Cheyenne Prairie's commercial operation date. Final rates were approved on April 1, 2015, effective October 1, 2014.

- In January 2015, Colorado Electric implemented new rates in accordance with the CPUC approval received on December 19, 2014 for an annual electric revenue increase of $3.1 million. The approval also allowed a 9.83% return on equity and a capital structure of 49.83% equity and 50.17% debt, as well as approving implementation of a construction financing rider. This approval allows Colorado Electric to recover increased operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The implementation of the rider allows Colorado Electric to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that is currently being constructed to replace the retired W.N. Clark power plant.

- In January 2015, Kansas Gas implemented new base rates in accordance with the rate request approval received on December 16, 2014 from the KCC to increase base rates by $5.2 million. This increase in base rates allows Kansas Gas to recover infrastructure and increased operating costs. The approval was a Global Settlement and did not stipulate return on equity and capital structure.

Non-regulated Energy Group

- Our Oil and Gas segment was impacted by lower commodity prices for crude oil and natural gas for the three and nine months ended September 30, 2015 compared to the same periods in 2014. The average hedged price received for natural gas decreased by 37% and 38%, respectively for the three and nine months ended September 30, 2015 compared to the same periods in 2014. The average hedged price received for oil decreased by 27% and 24%, respectively, for the three and nine months ended September 30, 2015 compared to the same periods in 2014. Oil and Gas production volumes increased 17% and 24%, respectively, for the three and nine months ended September 30, 2015 compared to the same periods in 2014.

- We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis, known as a ceiling test. For the three and nine months ended September 30, 2015, our Oil and Gas segment recorded non-cash ceiling test impairments of $62 million and $178 million, respectively, as a result of continued low commodity prices. Using our current reserves information, further ceiling test impairments will occur in the fourth quarter of 2015 if commodity prices for crude oil and natural gas remain at current levels.

- During the second quarter of 2015, we decreased our planned 2016 and 2017 capital expenditures at our Oil and Gas segment from $122 million and $120 million to $12 million and $15 million, respectively, based on our expectation of continued low commodity prices. We recently finished drilling the last of 13 Mancos Shale wells for our 2014/2015 drilling program on three separate surface pads in the Piceance Basin. We placed three wells on production in the first quarter of 2015 and three more in the third quarter of 2015, and production results to date from these wells have been favorable, and exceeded our expectations. We expect to place three more wells on production in the fourth quarter of 2015. In the first quarter of 2015, we increased our 2015 planned capital expenditures to $167 million from $123 million, and now expect our total 2015 capital expenditures to be approximately $173 million. The overall change from $123 million to $173 million is due to approximately $50 million of 2014 drilling program carryover and another $35 million for non-consenting working interest owners in the program, partially offset by approximately $24 million from the completion deferral of our four remaining Mancos wells. Completion of these four remaining wells is being deferred based on the positive results of our other nine wells, insufficient gas processing capacity, and our expectation of continued low commodity prices.

- Our Power Generation segment initiated a strategic assessment of our non-regulated power plants, including the possible sale of certain of those assets. We have received multiple recent inquiries regarding potential sale of long-term contracted assets, such as Colorado IPP. We are currently evaluating the sale of up to 49.9% of Colorado IPP based on the ability to monetize assets under favorable terms. The proceeds from a potential sale of our Colorado IPP assets would lower the amount of equity and debt needed to fund the SourceGas acquisition.

- Due to uncertainties related to the Clean Power Plan issued by the EPA, the decision to exercise the option to purchase Wygen I by Cheyenne Light from Black Hills Wyoming has been delayed. Within the existing PPA between Black Hills Wyoming and Cheyenne Light expiring on December 31, 2022, Cheyenne Light has an option to purchase Black Hills Wyoming's 76.5% ownership of Wygen I through 2019 at $2.55 million per MW adjusted for capital additions and depreciation.

Corporate Activities

- On October 2, 2015, we executed a 10 year, $250 million notional amount, 2.29% Swap Lock to hedge the risks of interest rate movement between the hedge date and the expected pricing date for our anticipated long-term debt financing. The swap will be accounted for as a cash flow hedge and any gain or loss will be recorded in Accumulated Other Comprehensive Income (loss). The forward-starting interest rate swap can be used to lock-in interest rates on future debt issuances we anticipate completing in 2016. The swap has a mandatory termination date of April 12, 2027.

- On July 12, 2015, we entered into a definitive agreement to acquire SourceGas for approximately $1.89 billion, including $200 million in capital expenditures through closing and the assumption of $700 million in debt projected at closing. The effective purchase price is $1.74 billion after taking into account approximately $150 million in tax benefits associated with acquired NOLs and the step up in certain assets including goodwill resulting from the transaction. To fund the transaction, we entered into a commitment letter for a 1-year, $1.17 billion senior unsecured fully committed bridge facility provided by Credit Suisse. SourceGas operates four regulated natural gas utilities serving approximately 425,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. The transaction is subject to customary closing conditions, regulatory approvals from the APSC, CPUC, NPSC and WPSC, and was also subject to notification, clearance and reporting requirements under the Hart-Scott-Rodino Act, which waiting period expired on August 18, 2015. On August 10, 2015, we filed joint applications with the APSC, CPUC, NPSC and WPSC, requesting a March 1, 2016 approval date in all four filings. The discovery process with all four state commissions is ongoing and the acquisition is expected to close during the first half of 2016.

- On July 14, 2015, Moody's affirmed the BHC credit rating of Baa1 and revised the outlook to negative due to our announcement to acquire SourceGas.

- On July 13, 2015, S&P affirmed the BHC credit rating of BBB with stable outlook after our announcement to acquire SourceGas.

- On July 13, 2015, Fitch affirmed the BHC credit rating of BBB+ and revised the outlook to negative due to our announcement to acquire SourceGas.

- On June 26, 2015, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term one year, 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.

- On April 13, 2015, we entered into a new $300 million unsecured term loan. The loan has a two-year term with a maturity date of April 12, 2017. Proceeds of the term note were used to repay the existing $275 million term note due June 19, 2015.

Operating Results

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

Utilities Group

We report two segments within the Utilities Group: Electric Utilities and Gas Utilities. The Electric Utilities segment includes the regulated electric operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas operations of Cheyenne Light. The Gas Utilities segment includes the regulated natural gas utility operations of Black Hills Energy in Colorado, Iowa, Kansas and Nebraska.

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

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

Electric Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue — electric	$178,590	$169,834	$8,756	$512,530	$492,743	$19,787
Revenue — gas	6,220	4,717	1,503	30,938	25,794	5,144
Total revenue	184,810	174,551	10,259	543,468	518,537	24,931
Fuel, purchased power and cost of gas — electric	71,253	75,190	(3,937)	203,128	223,332	(20,204)
Purchased gas — gas	2,101	2,014	87	15,968	14,339	1,629
Total fuel, purchased power and cost of gas	73,354	77,204	(3,850)	219,096	237,671	(18,575)
Gross margin — electric	107,337	94,644	12,693	309,402	269,411	39,991
Gross margin — gas	4,119	2,703	1,416	14,970	11,455	3,515
Total gross margin	111,456	97,347	14,109	324,372	280,866	43,506
Operations and maintenance	43,658	39,052	4,606	131,466	121,923	9,543
Depreciation and amortization	21,109	19,635	1,474	62,694	57,996	4,698
Total operating expenses	64,767	58,687	6,080	194,160	179,919	14,241
Operating income	46,689	38,660	8,029	130,212	100,947	29,265

Interest expense, net	(13,084)	(11,730)	(1,354)	(40,475)	(35,572)	(4,903)
Other income (expense), net	585	330	255	825	938	(113)
Income tax benefit (expense)	(12,208)	(9,106)	(3,102)	(31,949)	(22,157)	(9,792)
Net income (loss)	$21,982	$18,154	$3,828	$58,613	$44,156	$14,457

	Three Months Ended September 30,		Nine Months Ended September 30,	
Revenue - Electric (in thousands)	2015	2014	2015	2014
Residential:				
Black Hills Power	$18,471	$15,941	$54,081	$50,333
Cheyenne Light	9,837	8,982	29,031	26,822
Colorado Electric	27,586	26,104	74,303	72,099
Total Residential	55,894	51,027	157,415	149,254
Commercial:				
Black Hills Power	27,156	24,747	76,330	67,475
Cheyenne Light	16,991	15,682	48,550	45,313
Colorado Electric	24,649	23,989	70,368	68,980
Total Commercial	68,796	64,418	195,248	181,768
Industrial:				
Black Hills Power	8,364	6,816	25,122	21,685
Cheyenne Light	9,493	7,538	26,657	22,066
Colorado Electric	10,885	9,515	32,041	28,088
Total Industrial	28,742	23,869	83,820	71,839
Municipal:				
Black Hills Power	1,024	964	2,741	2,602
Cheyenne Light	552	453	1,650	1,421
Colorado Electric	3,173	3,513	9,191	10,097
Total Municipal	4,749	4,930	13,582	14,120
Total Retail Revenue - Electric	158,181	144,244	450,065	416,981
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	4,563	5,551	13,962	15,622
Off-system Wholesale:				
Black Hills Power	5,417	6,278	18,718	20,764
Cheyenne Light	854	1,810	3,807	5,984
Colorado Electric	515	879	1,017	4,874
Total Off-system Wholesale	6,786	8,967	23,542	31,622
Other Revenue:				
Black Hills Power	7,116	7,432	19,478	21,255
Cheyenne Light	659	625	1,700	1,912
Colorado Electric	1,285	3,015	3,783	5,351
Total Other Revenue	9,060	11,072	24,961	28,518
Total Revenue - Electric	$178,590	$169,834	$512,530	$492,743

Quantities Generated and Purchased (in MWh)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Generated —				
Coal-fired:				
Black Hills Power	389,784	414,551	1,166,381	1,168,641
Cheyenne Light [(a)]	142,887	176,603	517,685	509,239
Total Coal-fired	532,671	591,154	1,684,066	1,677,880
Natural Gas and Oil:				
Black Hills Power [(b)]	37,721	12,054	57,482	17,026
Cheyenne Light [(b)]	24,331	—	34,881	—
Colorado Electric [(c)]	49,343	60,982	87,090	119,650
Total Natural Gas and Oil	111,395	73,036	179,453	136,676
Wind:				
Colorado Electric	8,884	8,862	28,152	36,420
Total Wind	8,884	8,862	28,152	36,420
Total Generated:				
Black Hills Power	427,505	426,605	1,223,863	1,185,667
Cheyenne Light	167,218	176,603	552,566	509,239
Colorado Electric	58,227	69,844	115,242	156,070
Total Generated	652,950	673,052	1,891,671	1,850,976
Purchased —				
Black Hills Power	307,984	336,160	1,097,319	1,132,425
Cheyenne Light	215,913	199,989	576,843	604,532
Colorado Electric	543,432	490,378	1,470,478	1,427,677
Total Purchased	1,067,329	1,026,527	3,144,640	3,164,634
Total Generated and Purchased:				
Black Hills Power	735,489	762,765	2,321,182	2,318,092
Cheyenne Light	383,131	376,592	1,129,409	1,113,771
Colorado Electric	601,659	560,222	1,585,720	1,583,747
Total Generated and Purchased	1,720,279	1,699,579	5,036,311	5,015,610

(a) Decrease was due to a planned annual outage at Wygen II during the three months ended September 30, 2015.
(b) Cheyenne Prairie was placed into commercial service on October 1, 2014.
(c) Decrease in 2015 generation was primarily driven by commodity prices that impacted power marketing sales.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Quantity Sold (in MWh)	2015	2014	2015	2014
Residential:				
Black Hills Power	128,474	120,117	385,454	398,821
Cheyenne Light	63,410	64,468	189,078	192,451
Colorado Electric	178,786	169,760	472,767	455,647
Total Residential	370,670	354,345	1,047,299	1,046,919
Commercial:				
Black Hills Power	218,305	214,590	603,272	575,579
Cheyenne Light	138,841	140,871	400,400	396,971
Colorado Electric	197,717	186,988	532,306	519,406
Total Commercial	554,863	542,449	1,535,978	1,491,956
Industrial:				
Black Hills Power	109,725	96,443	324,078	302,208
Cheyenne Light	131,785	98,424	361,061	284,010
Colorado Electric	132,190	112,401	361,222	313,608
Total Industrial	373,700	307,268	1,046,361	899,826
Municipal:				
Black Hills Power	9,322	9,387	24,058	24,781
Cheyenne Light	2,334	2,272	7,058	6,896
Colorado Electric	34,860	34,765	91,781	92,838
Total Municipal	46,516	46,424	122,897	124,515
Total Retail Quantity Sold	1,345,749	1,250,486	3,752,535	3,563,216
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power [(a)]	65,952	83,714	215,119	250,941
Off-system Wholesale:				
Black Hills Power	154,215	171,189	646,066	595,483
Cheyenne Light	18,558	45,066	92,092	139,672
Colorado Electric [(b)]	16,071	17,754	32,041	98,678
Total Off-system Wholesale	188,844	234,009	770,199	833,833
Total Quantity Sold:				
Black Hills Power	685,993	695,440	2,198,047	2,147,813
Cheyenne Light	354,928	351,101	1,049,689	1,020,000
Colorado Electric	559,624	521,668	1,490,117	1,480,177
Total Quantity Sold	1,600,545	1,568,209	4,737,853	4,647,990
Other Uses, Losses or Generation, net [(c)]:				
Black Hills Power	49,496	67,325	123,135	170,279
Cheyenne Light	28,203	25,491	79,720	93,771
Colorado Electric	42,035	38,554	95,603	103,570

Total Other Uses, Losses and Generation, net	119,734	131,370	298,458	367,620
Total Energy	1,720,279	1,699,579	5,036,311	5,015,610

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(a) Decrease was driven by load requirements related to a Wygen III unit-contingent PPA.

(b) Decrease in 2015 generation was primarily driven by commodity prices that impacted power marketing sales.

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

Degree Days	Three Months Ended September 30, 2015			2014	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
Black Hills Power	127	(40)%	(47)%	241	15%
Cheyenne Light	118	(57)%	(46)%	220	(20)%
Colorado Electric	4	(95)%	(93)%	54	(37)%
Combined [(a)]	70	(58)%	(54)%	151	(9)%
Cooling Degree Days:					
Black Hills Power	477	(15)%	25%	382	(32)%
Cheyenne Light	343	14%	20%	286	(5)%
Colorado Electric	1,015	39%	43%	710	(3)%
Combined [(a)]	697	19%	36%	514	(12)%

Degree Days	Nine Months Ended September 30, 2015			2014	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Heating Degree Days:					
Black Hills Power	4,005	(10)%	(14)%	4,676	6%
Cheyenne Light	3,942	(12)%	(15)%	4,617	3%
Colorado Electric	3,026	(8)%	(10)%	3,357	2%
Combined [(a)]	3,543	(10)%	(13)%	4,055	3%
Cooling Degree Days:					
Black Hills Power	573	(14)%	19%	481	(28)%
Cheyenne Light	405	15%	21%	336	(5)%
Colorado Electric	1,260	32%	37%	919	(4)%
Combined [(a)]	855	16%	31%	654	(11)%

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

Electric Utilities Power Plant Availability	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Coal-fired plants [(a)]	89.0%	97.0%	92.2%	92.4%
Other plants [(b)] [(c)]	96.4%	95.6%	95.3%	87.9%
Total availability	93.7%	96.2%	94.2%	89.8%

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

(b) The nine months ended September 30, 2014 include a planned outage at Ben French CT's #1 and #2 for a controls upgrade.

(c) The nine months ended September 30, 2014, reflects an unplanned outage due to a turbine bearing replacement and combustor upgrade at Pueblo Airport Generation Station.

Cheyenne Light Natural Gas Distribution

Included in the Electric Utilities are Cheyenne Light's natural gas distribution systems. The following table summarizes certain operating information for these natural gas distribution operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenue - Natural Gas (in thousands):				
Residential	$3,133	$2,912	$16,386	$15,655
Commercial	1,672	1,124	9,039	7,075
Industrial	570	465	3,004	2,368
Other Sales Revenue	845	216	2,509	696
Total Revenue - Natural Gas	$6,220	$4,717	$30,938	$25,794
Gross Margin (in thousands):				
Residential	$2,413	$1,969	$8,936	$7,956
Commercial	754	451	3,073	2,413
Industrial	58	67	403	390
Other Gross Margin	845	216	2,509	696
Total Gross Margin	$4,070	$2,703	$14,921	$11,455
Volumes Sold (Dth):				
Residential	163,695	183,327	1,573,852	1,669,219
Commercial	187,272	130,939	1,256,089	979,826
Industrial	70,276	77,175	490,334	453,660
Total Volumes Sold	421,243	391,441	3,320,275	3,102,705

Results of Operations for the Electric Utilities for the Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014: Net income for the Electric Utilities was $22 million for the three months ended September 30, 2015, compared to Net income of $18 million for the three months ended September 30, 2014, as a result of:

Gross margin increased primarily due to a return on additional investment in our generating facilities which increased gross margins by $9.5 million compared to the same period in the prior year. Cooling degree days increased by 36 percent compared to the same period in the prior year, and were 19 percent higher than normal, driving an increase of $3.3 million. Electric margins were favorably impacted by higher retail load and demand that increased MWh sold, driving an increase of $1.7 million. Gas gross margins at Cheyenne Light were favorably impacted by our MGTC and Energy West Wyoming system acquisitions increasing margins by $1.2 million. Partially offsetting these increases was a $0.8 million decrease in technical service revenue from facility improvements at one of our large industrial customers in the prior year.

Operations and maintenance increased primarily due to costs related to Cheyenne Prairie, which was placed into commercial service on October 1, 2014, an increase in property taxes and an increase in employee costs primarily from our Energy West Wyoming system acquisition.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of Cheyenne Prairie, which was placed into commercial service on October 1, 2014.

Interest expense, net increased primarily due to interest costs from the $160 million of permanent financing placed during the fourth quarter of 2014 for Cheyenne Prairie.

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

Income tax benefit (expense): The effective tax rate was higher for the three months ended September 30, 2015 primarily due to an unfavorable true-up adjustment in the current year compared to the same period in the prior year.

Results of Operations for the Electric Utilities for the Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014: Net income for the Electric Utilities was $59 million for the nine months ended September 30, 2015, compared to Net income of $44 million for the nine months ended September 30, 2014, as a result of:

Gross margin increased primarily due to a return on additional investment in our generating facilities which increased gross margins by $26.5 million compared to the same period in the prior year. Electric margins were favorably impacted by higher retail load and demand that increased MWh sold driving an increase of $7.5 million. Colorado Electric received approval of a one-time settlement agreement from the CPUC on our renewable energy standard adjustment related to Busch Ranch, which increased margins by $2.1 million. Gas margins at Cheyenne Light were favorably impacted by our MGTC and Energy West Wyoming system acquisitions increasing margins by $3.4 million. Partially offsetting these increases is a $0.6 million impact from weather compared to the same period in the prior year. A decrease in heating degree days of 13% partially offset a 31% increase in cooling degree days.

Operations and maintenance increased primarily due to costs related to Cheyenne Prairie, which was placed into commercial service on October 1, 2014, and an increase in employee costs primarily from our Energy West Wyoming system acquisition.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of Cheyenne Prairie, which was placed into commercial service on October 1, 2014.

Interest expense, net increased primarily due to interest costs from the $160 million of permanent financing placed during the fourth quarter of 2014 for Cheyenne Prairie.

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

Income tax benefit (expense): The effective tax rate was higher in 2015 primarily due to the increase in liability with respect to uncertain tax positions related to research and development credits.

Gas Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$61,576	$71,595	$(10,019)	$362,803	$418,177	$(55,374)
Other — non-regulated services	7,358	7,140	218	23,208	22,394	814
Total revenue	68,934	78,735	(9,801)	386,011	440,571	(54,560)
Cost of sales						
Natural gas — regulated	22,511	32,614	(10,103)	204,526	255,654	(51,128)
Other — non-regulated services	4,072	3,896	176	11,556	11,293	263
Total cost of sales	26,583	36,510	(9,927)	216,082	266,947	(50,865)
Gross margin	42,351	42,225	126	169,929	173,624	(3,695)
Operations and maintenance	30,570	31,646	(1,076)	96,878	100,478	(3,600)
Depreciation and amortization	7,115	6,634	481	21,517	19,693	1,824
Total operating expenses	37,685	38,280	(595)	118,395	120,171	(1,776)
Operating income (loss)	4,666	3,945	721	51,534	53,453	(1,919)
Interest expense, net	(3,635)	(3,766)	131	(11,025)	(11,341)	316
Other income (expense), net	569	(3)	572	577	(1)	578
Income tax benefit (expense)	30	1,421	(1,391)	(14,079)	(13,822)	(257)
Net income (loss)	$1,630	$1,597	$33	$27,007	$28,289	$(1,282)

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Revenue (in thousands)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Residential:				
Colorado	$5,343	$5,996	$40,940	$39,118
Nebraska	12,694	14,032	84,766	94,443
Iowa	10,461	13,013	69,805	89,829
Kansas	7,556	8,796	45,698	52,421
Total Residential	36,054	41,837	241,209	275,811
Commercial:				
Colorado	1,223	1,411	8,147	8,168
Nebraska	2,897	3,330	25,004	27,986
Iowa	3,778	5,964	30,301	43,080
Kansas	2,382	2,520	16,440	17,815
Total Commercial	10,280	13,225	79,892	97,049
Industrial:				
Colorado	1,058	1,070	1,305	1,651
Nebraska	389	203	1,288	510
Iowa	225	615	1,923	2,928
Kansas	7,464	8,528	11,961	15,246
Total Industrial	9,136	10,416	16,477	20,335
Transportation:				
Colorado	124	124	727	666
Nebraska	2,128	2,054	9,955	10,326
Iowa	849	895	3,548	3,639
Kansas	1,693	1,654	5,624	5,710
Total Transportation	4,794	4,727	19,854	20,341
Other Sales Revenue:				
Colorado	25	25	441	92
Nebraska	501	528	1,771	1,882
Iowa	120	158	467	572
Kansas	666	678	2,692	2,094
Total Other Sales Revenue	1,312	1,389	5,371	4,640
Total Regulated Revenue	61,576	71,594	362,803	418,176
Non-regulated Services	7,358	7,141	23,208	22,395
Total Revenue	$68,934	$78,735	$386,011	$440,571

Gross Margin (in thousands)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Residential:				
Colorado	$2,892	$2,917	$12,918	$12,887
Nebraska	9,023	9,064	37,729	39,877
Iowa	8,277	8,301	30,989	32,504
Kansas	5,836	6,025	23,518	24,137
Total Residential	26,028	26,307	105,154	109,405
Commercial:				
Colorado	482	497	2,096	2,164
Nebraska	1,493	1,504	7,876	8,440
Iowa	1,903	1,984	8,656	9,509
Kansas	1,348	1,263	6,228	5,942
Total Commercial	5,226	5,248	24,856	26,055
Industrial:				
Colorado	251	248	341	408
Nebraska	130	56	369	157
Iowa	41	45	172	191
Kansas	1,280	1,061	2,230	1,994
Total Industrial	1,702	1,410	3,112	2,750
Transportation:				
Colorado	124	124	727	666
Nebraska	2,128	2,054	9,955	10,326
Iowa	849	895	3,548	3,639
Kansas	1,693	1,654	5,624	5,710
Total Transportation	4,794	4,727	19,854	20,341
Other Sales Margins:				
Colorado	23	25	440	92
Nebraska	501	529	1,771	1,883
Iowa	120	158	467	572
Kansas	669	577	2,621	1,425
Total Other Sales Margins	1,313	1,289	5,299	3,972
Total Regulated Gross Margin	39,063	38,981	158,275	162,523
Non-regulated Services	3,288	3,244	11,654	11,101
Total Gross Margin	$42,351	$42,225	$169,929	$173,624

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Residential:				
Colorado	456,779	537,302	4,453,521	4,577,702
Nebraska	713,809	876,069	7,820,461	9,140,645
Iowa	499,839	717,413	7,061,074	8,610,378
Kansas	396,855	542,998	4,346,965	5,140,443
Total Residential	2,067,282	2,673,782	23,682,021	27,469,168
Commercial:				
Colorado	143,356	162,936	979,082	1,053,938
Nebraska	287,698	325,327	2,911,344	3,285,506
Iowa	430,914	581,028	3,996,378	4,951,717
Kansas	241,909	249,809	2,011,756	2,183,324
Total Commercial	1,103,877	1,319,100	9,898,560	11,474,485
Industrial:				
Colorado	212,080	209,337	258,017	321,130
Nebraska	85,937	32,003	239,262	71,136
Iowa	42,396	71,188	321,178	384,761
Kansas [(a)]	2,092,545	1,788,406	3,118,446	3,053,101
Total Industrial	2,432,958	2,100,934	3,936,903	3,830,128
Wholesale and Other:				
Nebraska	—	39	—	39
Kansas [(a)]	—	18,836	14,902	119,743
Total Wholesale and Other	—	18,875	14,902	119,782
Total Distribution Quantities Sold	5,604,117	6,112,691	37,532,386	42,893,563
Transportation:				
Colorado	99,086	105,221	709,572	645,364
Nebraska	6,428,867	6,262,525	21,987,850	22,849,299
Iowa	4,295,910	4,193,172	14,983,598	14,669,877
Kansas	3,902,116	3,799,470	11,763,592	12,220,766
Total Transportation	14,725,979	14,360,388	49,444,612	50,385,306
Total Distribution Quantities Sold and Transportation	20,330,096	20,473,079	86,976,998	93,278,869

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

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

	Three Months Ended September 30,				
	2015			2014	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Colorado	41	(77)%	(65)%	117	(35)%
Nebraska	35	(64)%	(63)%	95	(1)%
Iowa	85	(39)%	(58)%	200	44%
Kansas [(a)]	13	(76)%	(79)%	62	13%
Combined [(b)]	54	(57)%	(61)%	137	6%

	Nine Months Ended September 30,				
	2015			2014	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Colorado	3,463	(11)%	(11)%	3,900	—%
Nebraska	3,523	(5)%	(11)%	3,947	6%
Iowa	4,568	9%	(11)%	5,149	23%
Kansas [(a)]	2,738	(8)%	(15)%	3,231	9%
Combined [(b)]	3,887	(1)%	(11)%	4,371	12%

(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism.

Results of Operations for the Gas Utilities for the Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014: Net income for the Gas Utilities was $1.6 million for the three months ended September 30, 2015, compared to Net income of $1.6 million for the three months ended September 30, 2014, as a result of:

Gross margin was comparable to the same period in the prior year, reflecting a decrease of $1.0 million from milder weather and lower residential volumes sold, offset by base rate adjustments and riders at Kansas Gas, and increased transportation revenue. Heating degree days were 61% lower for the three months ended September 30, 2015, compared to the same period in the prior year and 57% lower than normal in the current year, compared to 6% higher than normal in the prior year.

Operations and maintenance decreased due to lower allowance for uncollectible account expense, lower employee costs and lower operating expenses.

Depreciation and amortization increased primarily due to a higher asset base than the same period in the prior year.

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

Other income (expense), net increased primarily due to a gain on the sale of land of $0.4 million.

Income tax benefit (expense): The effective tax rate for both periods presented was favorably impacted by a true-up adjustment attributable to the prior year.

Results of Operations for the Gas Utilities for the Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014: Net income for the Gas Utilities was $27 million for the nine months ended September 30, 2015, compared to Net income of $28 million for the nine months ended September 30, 2014, as a result of:

Gross margin decreased primarily due to a $6.5 million impact from milder weather than in the same period in the prior year. Heating degree days were 11% lower for the nine months ended September 30, 2015, compared to the same period in the prior year and 1% lower than normal in the current year, compared to 12% higher than normal in the prior year. Partially offsetting this weather impact was a $1.8 million increase from base rate adjustments and riders at Kansas Gas which were effective January 1, 2015, a $1.1 million increase from year-over-year customer growth, and an increase of approximately $0.5 million from non-regulated services.

Operations and maintenance decreased primarily due to lower allowance for uncollectible account expense, lower employee costs and lower operating expenses, partially offset by an increase in property taxes.

Depreciation and amortization increased primarily due to a higher asset base than the same period in the prior year.

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

Other income (expense), net increased primarily due to a gain on the sale of land of $0.4 million.

Income tax benefit (expense): The effective tax rate is higher in 2015 primarily due to a less favorable tax true-up adjustment when compared to the prior year.

Regulatory Matters — Utilities Group

For more information on enacted regulatory provisions with respect to the states in which the Utilities Group operates, see Part I, Items 1 and 2 of our 2014 Annual Report on Form 10-K.

The following summarizes our 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
Black Hills Power [(a)]	Electric	3/2014	10/2014	$14.6	$6.9
Kansas Gas [(b)]	Gas	4/2014	1/2015	$7.3	$5.2
Colorado Electric [(c)]	Electric	4/2014	1/2015	$4.0	$3.1

(a) On March 2, 2015, the SDPUC issued an order approving a rate stipulation and agreement authorizing an increase for Black Hills Power of $6.9 million in annual electric revenue. The agreement was a Global Settlement and did not stipulate return on equity and capital structure. The SDPUC's decision provides Black Hills Power a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for this natural gas-fired facility. Black Hills Power implemented interim rates on October 1, 2014, coinciding with Cheyenne Prairie's commercial operation date. Final rates were approved on April 1, 2015, effective October 1, 2014.

(b) In January 2015, Kansas Gas implemented new base rates in accordance with the rate request approval received on December 16, 2014 from the KCC to increase base rates by $5.2 million. This increase in base rates allows Kansas Gas to recover infrastructure and increased operating costs. The approval was a Global Settlement and did not stipulate return on equity and capital structure.

(c) In January 2015, Colorado Electric implemented new rates in accordance with the CPUC approval received on December 19, 2014 for an annual electric revenue increase of $3.1 million. The approval also allowed a 9.83% return on equity and a capital structure of 49.83% equity and 50.17% debt, as well as approving implementation of a construction financing rider. This approval allows Colorado Electric to recover increased operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The implementation of the rider also allows Colorado Electric to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

Capital Investment Recovery Surcharge filings (in millions):

	Type of Service	Date Requested	Effective Date	Capital Surcharge Requested	Capital Surcharge Approved
Nebraska Gas [(a)]	Gas	4/2015	8/2015	$1.5	$1.5
Iowa Gas [(b)]	Gas	3/2015	6/2015	$0.9	$0.9

(a) On April 6, 2015, Nebraska Gas filed with the NPSC for a capital investment recovery surcharge increase of $1.5 million. Nebraska Gas received approval from the NPSC on July 27, 2015.

(b) On March 17, 2015, Iowa Gas filed with the IUB for a capital investment recovery surcharge increase of $0.9 million. Iowa Gas received approval from the IUB on May 28, 2015.

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 60% equity and 40% debt, and seeks a utility-like return. Based on historical performance, the cost of production is expected to be more stable and predictable than the spot market price of natural gas.

Non-regulated Energy Group

We report three segments within our Non-regulated Energy Group: Power Generation, Coal Mining and Oil and Gas.

Power Generation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue	$23,251	$22,021	$1,230	$68,234	$66,349	$1,885
Operations and maintenance	7,456	7,306	150	23,767	23,714	53
Depreciation and amortization	1,078	1,122	(44)	3,327	3,485	(158)
Total operating expense	8,534	8,428	106	27,094	27,199	(105)
Operating income	14,717	13,593	1,124	41,140	39,148	1,992
Interest expense, net	(753)	(920)	167	(2,427)	(2,782)	355
Other (expense) income, net	35	9	26	40	2	38
Income tax (expense) benefit	(4,932)	(4,853)	(79)	(13,992)	(13,272)	(720)
Net income (loss)	$9,067	$7,829	$1,238	$24,761	$23,096	$1,665

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Quantities Sold, Generated and Purchased (MWh) [(a)]				
Sold				
Black Hills Colorado IPP	310,689	300,231	862,540	859,387
Black Hills Wyoming [(b)]	172,807	151,435	497,922	430,420
Total Sold	483,496	451,666	1,360,462	1,289,807
Generated				
Black Hills Colorado IPP	310,689	300,231	862,540	859,387
Black Hills Wyoming	143,728	141,420	420,968	423,556
Total Generated	454,417	441,651	1,283,508	1,282,943
Purchased				
Black Hills Wyoming [(b)]	30,336	6,298	67,827	7,303
Total Purchased	30,336	6,298	67,827	7,303

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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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Contracted power plant fleet availability:				
Coal-fired plant	98.9 %	96.1 %	98.2 %	98.0 %
Natural gas-fired plants	99.2 %	99.2 %	99.0 %	98.7 %
Total availability	99.1 %	98.5 %	98.8 %	98.6 %

Results of Operations for Power Generation for the Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014: Net income for the Power Generation segment was $9.1 million for the three months ended September 30, 2015, compared to Net income of $7.8 million for the same period in 2014 as a result of:

Revenue increased primarily due to an increase in PPA pricing and an increase in fired-hours and MWh sold, partially offset by a decrease in off-system sales.

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 lower in 2015 primarily due to true-up adjustment related to the prior year filed tax return.

Results of Operations for Power Generation for the Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014: Net income for the Power Generation segment was $25 million for the nine months ended September 30, 2015, compared to Net income of $23 million for the same period in 2014 as a result of:

Revenue increased primarily due to an increase in PPA pricing, and an increase in fired-hours, partially offset by the net effect of the expiration of the CTII PPA and subsequent 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 in 2015 was comparable to the prior year.

Coal Mining

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue	$16,966	$15,573	$1,393	$49,625	$45,722	$3,903
Operations and maintenance	10,841	9,875	966	31,406	30,029	1,377
Depreciation, depletion and amortization	2,484	2,542	(58)	7,448	7,802	(354)
Total operating expenses	13,325	12,417	908	38,854	37,831	1,023
Operating income (loss)	3,641	3,156	485	10,771	7,891	2,880
Interest (expense) income, net	(98)	(108)	10	(289)	(324)	35
Other income, net	567	535	32	1,700	1,727	(27)
Income tax benefit (expense)	(1,063)	(945)	(118)	(3,076)	(2,176)	(900)
Net income (loss)	$3,047	$2,638	$409	$9,106	$7,118	$1,988

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Tons of coal sold	1,041	1,082	3,136	3,232
Cubic yards of overburden moved [(a)]	1,747	1,005	4,552	2,925
Revenue per ton	$16.30	$14.38	$15.82	$14.15

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

Results of Operations for Coal Mining for the Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014: Net income for the Coal Mining segment was $3.0 million for the three months ended September 30, 2015, compared to Net income of $2.6 million for the same period in 2014 as a result of:

Revenue increased primarily due to a 13% increase in price per ton sold, partially offset by a 4% decrease in tons sold. The increase in pricing was driven by the price re-opener on a coal contract with the third-party operator of the Wyodak plant which became effective in the third quarter of 2014, partially offset 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 materials and outside services for major maintenance on processing equipment and an increase in royalties driven by increased revenues, 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 comparable to the same period in the prior year.

Results of Operations for Coal Mining for the Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014: Net income for the Coal Mining segment was $9.1 million for the nine months ended September 30, 2015, compared to Net income of $7.1 million for the same period in 2014 as a result of:

Revenue increased primarily due to a 12% increase in price per ton sold, partially offset by a 3% decrease in tons sold. The increase in pricing was driven by the price re-opener on a coal contract with the third-party operator of the Wyodak plant which became effective in the third quarter of 2014, partially offset by contract price adjustments based on actual mining costs. Tons of coal sold was negatively impacted by a forced outage at Neil Simpson II, the closure of Neil Simpson I in March 2014 and a one-time coal stockpile sale occurring in the prior year. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operations and maintenance increased primarily due to materials and services on major maintenance on processing equipment, an increase in overburden moved and higher production taxes and royalties driven by increased revenue, 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 in 2015 is higher due primarily to the reduced impact of the tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue	$9,895	$13,471	$(3,576)	$33,481	$43,469	$(9,988)
Operations and maintenance	10,963	10,347	616	32,868	31,725	1,143
Depreciation, depletion and amortization	6,151	6,749	(598)	22,452	19,003	3,449
Impairment of long-lived assets	61,875	—	61,875	178,395	—	178,395
Total operating expenses	78,989	17,096	61,893	233,715	50,728	182,987
Operating income (loss)	(69,094)	(3,625)	(65,469)	(200,234)	(7,259)	(192,975)
Interest income (expense), net	(714)	(405)	(309)	(1,576)	(1,302)	(274)
Other income (expense), net	(163)	40	(203)	(379)	127	(506)
Impairment of equity investments	—	—	—	(5,170)	—	(5,170)
Income tax benefit (expense)	30,202	1,407	28,795	77,280	3,223	74,057
Net income (loss)	$(39,769)	$(2,583)	$(37,186)	$(130,079)	$(5,211)	$(124,868)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production:				
Bbls of oil sold	98,722	82,640	278,357	249,130
Mcf of natural gas sold	2,271,186	1,856,138	7,226,949	5,456,928
Bbls of NGL sold	19,342	33,035	81,383	102,079
Mcf equivalent sales	2,979,568	2,550,187	9,385,391	7,564,179

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Average price received: (a) (b)				
Oil/Bbl	$58.31	$80.42	$63.20	$83.19
Gas/Mcf	$1.69	$2.70	$1.89	$3.07
NGL/Bbl	$2.87	$35.78	$13.64	$38.46
Depletion expense/Mcfe	$1.64	$2.15	$2.03	$2.02

(a) Net of hedge settlement gains and losses.

(b) Ceiling test impairments of $62 million and $178 million were recorded for the three and nine months ended September 30, 2015. If crude oil and natural gas prices remain at or near the current levels, an additional ceiling impairment charge could occur in the fourth quarter of 2015.

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

	Three Months Ended September 30, 2015				Three Months Ended September 30, 2014			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation [(a)]	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation [(a)]	Production Taxes	Total
San Juan	$1.10	$1.01	$0.11	$2.22	$1.42	$1.32	$0.53	$3.27
Piceance	0.80	2.29	0.31	3.40	0.46	4.50	0.30	5.26
Powder River	1.57	—	0.56	2.13	1.29	—	1.27	2.56
Williston	1.59	—	0.62	2.21	1.26	—	1.21	2.47
All other properties	1.16	—	0.27	1.43	1.91	—	0.54	2.45
Total weighted average	$1.10	$1.21	$0.32	$2.63	$1.21	$1.60	$0.66	$3.47

	Nine Months Ended September 30, 2015				Nine Months Ended September 30, 2014			
Producing Basin	LOE	Gathering, Compression, Processing and Transportation [(a)]	Production Taxes	Total	LOE	Gathering, Compression, Processing and Transportation [(a)]	Production Taxes	Total
San Juan	$1.31	$1.23	$0.35	$2.89	$1.45	$1.25	$0.59	$3.29
Piceance	0.59	2.12	0.22	2.93	0.22	3.30	0.41	3.93
Powder River	2.14	—	0.65	2.79	1.69	—	1.25	2.94
Williston	0.98	—	0.35	1.33	1.14	—	1.46	2.60
All other properties	1.49	—	0.56	2.05	1.65	—	0.43	2.08
Total weighted average	$1.14	$1.24	$0.36	$2.74	$1.16	$1.35	$0.70	$3.21

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

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

We revised our presentation of these costs in 2014 to include both third-party costs and operations costs. A ten-year gas gathering and processing contract for natural gas production in our Piceance Basin became effective in March of 2014. This take-or-pay contract requires us to pay a fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. We did not meet the minimum requirements of this contract until mid-February 2015. Our gathering, compression and processing costs on a per Mcfe basis, as shown in the table above, will be higher in periods when we are not meeting the minimum contract requirements.

Results of Operations for Oil and Gas for the Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014: Net loss for the Oil and Gas segment was $40 million for the three months ended September 30, 2015, compared to Net loss of $2.6 million for the same period in 2014 as a result of:

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 27% decrease in the average hedged price received for crude oil sold, and a 37% decrease in the average hedged price received for natural gas sold. A production increase of 17%, driven primarily by three new Piceance Mancos Shale wells placed on production in the third quarter of 2015, partially offset the decrease in prices.

Operations and maintenance increased primarily due to severance costs, partially offset by 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 as a result of the impact from the ceiling test impairments incurred in the current year, partially offset by the depletion rate applied to greater production.

Impairment of long-lived assets represents a non-cash impairment in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The impairment reflected a 12 month average NYMEX price of $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead, for natural gas, and $59.21 per barrel, adjusted to $52.82 at the wellhead, for crude oil.

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

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 2015 was impacted by a favorable true-up adjustment.

Results of Operations for Oil and Gas for the Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014: Net loss for the Oil and Gas segment was $130 million for the nine months ended September 30, 2015, compared to Net loss of $5.2 million for the same period in 2014 as a result of:

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas resulting in a 24% decrease in the average hedged price received for crude oil sold, and a 38% decrease in the average hedged price received for natural gas sold. A production increase of 24%, driven primarily by six new Piceance Mancos Shale wells with three each placed on production in the first and third quarters of 2015, partially offset the decrease in prices.

Operations and maintenance increased primarily due to higher lease and field operation expenses from non-operated wells and water haulage, and severance costs, partially offset by lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization increased primarily due to greater production, partially offset by the reduction in our full cost pool as a result of the impact from ceiling test impairments incurred in the current year.

Impairment of long-lived assets represents a non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The write-down reflected a 12 month average NYMEX price of $3.06 per Mcf, adjusted to $1.72 per Mcf at the wellhead, for natural gas, and $59.21 per barrel, adjusted to $52.82 per barrel at the wellhead, for crude oil.

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

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

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

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

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended September 30, 2015 Compared to the Three Months Ended September 30, 2014: Net loss for Corporate was $5.9 million for the three months ended September 30, 2015, compared to Net loss of $0.3 million for the three months ended September 30, 2014. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition including approximately $3.0 million of bridge financing costs recognized in interest expense and approximately $1.8 million of labor attributed to the acquisition during the three months ended September 30, 2015 , compared to the three months ended September 30, 2014.

Results of Operations for Corporate activities for the Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014: Net loss for Corporate was $7.3 million for the nine months ended September 30, 2015, compared to Net loss of $1.1 million for the nine months ended September 30, 2014. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition including approximately $3.0 million of bridge financing costs recognized in interest expense and approximately $2.1 million of labor attributed to the acquisition during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014.

Critical Accounting Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2014 Annual Report on Form 10-K/A filed with the SEC. For more information on our critical accounting estimates, see Part II, Item 7 of our 2014 Annual Report on Form 10-K/A.

Liquidity and Capital Resources

OVERVIEW

BHC and its subsidiaries require 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 the Company 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.

The Company 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 September 30, 2015 we had $3.2 million of collateral posted related to our wholesale commodity contracts transactions, and no collateral posted related to our interest rate swap transactions. At September 30, 2015, we had sufficient liquidity to cover any additional collateral that could be required to be posted under these contracts.

Cash Flow Activities

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

Cash provided by (used in):	2015	2014	Increase (Decrease)
Operating activities	$365,873	$239,157	$126,716
Investing activities	$(356,660)	$(270,321)	$(86,339)
Financing activities	$8,410	$35,262	$(26,852)

Year-to-Date 2015 Compared to Year-to-Date 2014

Operating Activities

Net cash provided by operating activities was $366 million for the nine months ended September 30, 2015, compared to net cash provided by operating activities of $239 million for the same period in 2014 for a variance of $127 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $1.0 million higher for the nine months ended September 30, 2015 compared to the same period in the prior year; and

- Net inflows from operating assets and liabilities were $105 million for the nine months ended September 30, 2015, compared to net cash outflows of $32 million in the same period in the prior year. This $137 million variance was primarily due to:

- Cash inflows increased for the nine months ended September 30, 2015 compared to the same period in the prior year as a result of decreased gas volumes in inventory due to milder weather and lower natural gas prices; and

- Cash inflows increased as a result of lower customer receivables and lower working capital requirements for natural gas for the nine months ended September 30, 2015 compared to the same period in the prior year. Colder weather and higher natural gas prices during the first quarter 2014 peak winter heating season drove a significant increase in natural gas volumes sold, and in natural gas volumes purchased and fuel cost adjustments recorded in regulatory assets. These fuel cost adjustments deferred in the prior year are recovered through their respective cost mechanisms as allowed by the state utility commissions.

Investing Activities

Net cash used in investing activities was $357 million for the nine months ended September 30, 2015, compared to net cash used in investing activities of $270 million for the same period in 2014. The variance was primarily driven by:

- Capital expenditures of approximately $349 million for the nine months ended September 30, 2015 compared to $290 million for the nine months ended September 30, 2014. The increase is related primarily to higher capital expenditures at our Oil and Gas segment driven by drilling activity, including prior year completions that were affected by weather delays in the prior year. Capital expenditures also increased at our Coal Mine and Gas Utilities segments for the nine months ended September 30, 2015 compared to the prior year. Offsetting these 2015 capital expenditure increases is the construction of Cheyenne Prairie at our Electric Utilities segment occurring in the prior year; and

- Proceeds of $22 million received on the sale of an operating asset in 2014 at our Power Generation segment.

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2015 was $8 million, compared to $35 million of net cash provided by financing activities for the same period in 2014. The variance was primarily driven by:

- Net Long-term borrowings increased by $25 million due to our new $300 million Corporate term loan which replaced the $275 million Corporate term loan due on June 19, 2015; and

- Net Short-term borrowings under the revolving credit facility for the nine months ended September 30, 2015 were $60 million less than the prior year primarily due to higher working capital requirements in the prior year.

Dividends

Dividends paid on our common stock totaled $54 million for the nine months ended September 30, 2015, or $1.22 per share. On October 27, 2015, our board of directors declared a quarterly dividend of $0.405 per share payable December 1, 2015, which is equivalent to an annual dividend rate of $1.62 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 September 30, 2015	Letters of Credit at September 30, 2015	Available Capacity at September 30, 2015
Revolving Credit Facility	June 26, 2020	$500	$118	$31	$352

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 September 30, 2015.

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 floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have $75 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of approximately 1.3 years. These swaps have been designated as cash flow hedges for 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 $4.0 million at September 30, 2015.

Interest Rate Swap Lock

On October 2, 2015, we executed a 10 year, $250 million notional amount, 2.29% Swap Lock to hedge the risks of interest rate movement between the hedge date and the expected pricing date for our anticipated long-term debt financing. The swap will be accounted for as a cash flow hedge and any gain or loss will be recorded in Accumulated Other Comprehensive Income (loss). The forward-starting interest rate swap can be used to lock-in interest rates on future debt issuances we anticipate completing in 2016. The swap has a mandatory termination date of April 22, 2027.

Financing Activities

On July 12, 2015, in conjunction with the agreement to acquire SourceGas, we entered into a commitment letter with Credit Suisse to fund the transaction. Effective August 6, 2015, we entered into a Bridge Term Loan Agreement with Credit Suisse as the Administrative Agent and 10 additional banks, collectively, for commitments totaling $1.17 billion pursuant to the previously executed bridge commitment letter with Credit Suisse. We may draw up to $1.17 billion on this loan to fund the SourceGas acquisition and related expenses. The agreement contains the same customary affirmative and negative covenants as are in our Revolving Credit Agreement and Term Loan Credit Agreement, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and maintaining a recourse leverage ratio not to exceed 0.75 to 1.00. In the event we fund under the Bridge Term Loan Agreement, in certain circumstances, we are required to pay down those borrowings with funds received from the proceeds of equity and debt offerings and asset sales. Additionally, our Revolving Credit Facility and Term Loan Credit Agreements were amended in connection with the Bridge Term Loan Agreement to permit the assumption of certain indebtedness of SourceGas and to increase the Recourse Leverage Ratio in certain circumstances. In these amendments, the maximum Recourse Ratio is no greater than 0.65 to 1.00 at the end of any fiscal quarter, but may increase to (i) 0.70 to 1.00 at the end of any fiscal quarter during such four fiscal quarter period that the aggregate outstanding debt assumed or incurred in connection with our acquisition of SourceGas is equal to or greater than $1.25 billion and less than $1.46 billion or (ii) 0.75 to 1.00 at the end of any fiscal quarter during such four fiscal quarter period that the aggregate outstanding debt assumed or incurred in connection with our acquisition of SourceGas is equal to or greater than $1.46 billion.

On April 13, 2015, we entered into a new $300 million Corporate term loan expiring April 12, 2017. This new term loan replaced the $275 million Corporate term loan due on June 19, 2015. The additional $25 million, less interest and fees, was used for general corporate purposes. The cost of the borrowing under the new term loan is LIBOR plus a margin of 0.9%. The covenants on the new term loan are substantially the same as the Revolving Credit Facility.

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044.

Future Financing Plans

We anticipate the following financing activities:

- Execute permanent financing options for the acquisition of SourceGas that include:

  * $450 million to $600 million of equity and equity linked securities, including $200 to $300 million of unit mandatory convertibles
  * $450 million to $550 million in new long-term debt issuances

- Evaluate the conversion of our $300 million variable-rate Corporate term loan to fixed rate debt.

- Evaluate the implementation of an “at-the-market” equity offering.

- Consider executing additional forward locking swaps to hedge interest rate risk.

During the third quarter of 2015, our Power Generation segment initiated a strategic assessment of our non-regulated power plants, including the possible sale of certain of those assets. We have received multiple recent inquiries regarding potential sale of long-term contracted assets, such as Colorado IPP. We are currently evaluating the sale of up to 49.9% of Colorado IPP based on the ability to monetize assets under favorable terms. The proceeds from a potential minority interest sale of our Colorado IPP assets would lower the amount of equity and debt needed to fund the SourceGas acquisition. A decision regarding the potential sale is expected to be made during the fourth quarter of 2015.

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 Colorado, Iowa, Kansas, and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary’s liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of September 30, 2015, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $334 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 not to exceed 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 September 30, 2015, we were in compliance with this covenant.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2014 Annual Report on Form 10-K/A 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.

Following the announcement of the SourceGas acquisition on July 12, 2015, each of the rating agencies completed a review of BHC and BHP.

The following table represents the credit ratings and outlook of BHC from each rating agency's review on July 13, 2015, which are still applicable at September 30, 2015:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(1)]	BBB	Stable
Moody's[(2)]	Baa1	Negative
Fitch [(3)]	BBB+	Negative

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1) S&P reaffirmed BBB rating with stable outlook.
2) Moody's reaffirmed Baa1 rating and revised BHC's outlook from Stable to Negative reflecting uncertainties around regulatory approvals, efficiencies and financing clarity for the SourceGas acquisition.
3) Fitch reaffirmed BBB+ rating and revised BHC's outlook from Stable to Negative reflecting uncertainties around regulatory approvals, efficiencies and financing clarity for the SourceGas acquisition.

The following table represents the credit ratings of Black Hills Power from each rating agency's review on July 13, 2015, which are still applicable at September 30, 2015:

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

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

Capital Requirements

Acquisition of SourceGas

On July 12, 2015, we entered into a definitive agreement to acquire SourceGas for approximately $1.89 billion, which includes $200 million of projected capital expenditures through closing and the assumption of $700 million in debt projected at closing. The effective purchase price is estimated to be $1.74 billion after taking into account approximately $150 million in tax benefits associated with acquired NOLs and the step up in certain assets including goodwill resulting from the transaction. The purchase price is subject to customary post-closing adjustments for cash, capital expenditures, indebtedness and working capital. To fund the transaction, we entered into a commitment letter for a 1-year, $1.17 billion senior unsecured fully committed bridge facility provided by Credit Suisse. The acquisition of SourceGas is expected to close during the first half of 2016. We expect to finance the acquisition with equity proceeds of $450 million to $600 million, including $200 million to $300 million of unit mandatory convertibles, $450 million to $550 million of new long-term indebtedness, and assuming approximately $700 million of continuing debt of SourceGas, with the remainder funded from cash on hand and draws under our revolving credit agreement.

Capital Expenditures

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

	Expenditures for the Nine Months Ended September 30, 2015 (a)	Total 2015 Planned Expenditures (b)(e)	Total 2016 Planned Expenditures (d)(e)	Total 2017 Planned Expenditures (d)
Utilities:				
Electric Utilities	$129,812	$215,000	$318,000	$135,600
Gas Utilities	50,401	69,200	60,100	71,800
Cost of Service Gas	—	—	50,000	100,000
Non-regulated Energy:				
Power Generation	2,123	3,000	2,400	2,600
Coal Mining	8,895	12,000	6,000	6,600
Oil and Gas (c)	152,005	173,000	12,300	15,000
Corporate	5,129	6,100	2,000	3,600
	$348,365	$478,300	$450,800	$335,200

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(a) Expenditures for the nine months ended September 30, 2015 include the impact of accruals for property, plant and equipment.

(b) Includes actual capital expenditures for the nine months ended September 30, 2015.

(c) During the second quarter of 2015, we decreased our 2016 and 2017 planned capital expenditures at our Oil and Gas segment from $122 million and $120 million to $12 million and $15 million, respectively, based on our expectation of continued low commodity prices. We are currently drilling the last of 13 Mancos Shale wells for our 2014/2015 drilling program in the Piceance Basin. We placed three wells on production in the first quarter of 2015 and three wells in the third quarter of 2015, and we expect to place three more in the fourth quarter of 2015. Completion of the four remaining wells is being deferred based on the positive results of our nine wells, insufficient gas processing capacity, and our expectation of continued low commodity prices.

(d) Forecasted amounts for 2016 and 2017 do not include capital expenditures for SourceGas.

(e) Forecasted amounts for 2015 and 2016 have been adjusted to include capital expenditures for the Peak View Wind Project.

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

Contractual Obligations

There have been no significant changes in the contractual obligations from those previously disclosed in Note 18 of our Notes to the Consolidated Financial Statements in our 2014 Annual Report on Form 10-K/A except for those described in Note 2 and Note 19 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 19 of the Notes to the Consolidated Financial Statements in our 2014 Annual Report on Form 10-K/A, except for those described in Note 2 and Note 19 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q.

New Accounting Pronouncements

Other than the pronouncements reported in our 2014 Annual Report on Form 10-K/A 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 2014 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2014 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

	September 30, 2015	December 31, 2014	September 30, 2014
Net derivative (liabilities) assets	$(21,322)	$(16,914)	$(4,650)
Cash collateral offset in Derivatives	21,322	16,914	4,650
Cash Collateral included in Other current assets	2,631	3,093	5,437
Net asset (liability) position	$2,631	$3,093	$5,437

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2015 and 2016 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at September 30, 2015, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2015					
Swaps - MMBtu	—	—	—	1,000,000	1,000,000
Weighted Average Price per MMBtu	$—	$—	$—	$4.04	$4.04
2016					
Swaps - MMBtu	945,000	917,500	905,000	545,000	3,312,500
Weighted Average Price per MMBtu	$3.52	$3.50	$3.51	$3.90	$3.57
2017					
Swaps - MMBtu	270,000	270,000	270,000	270,000	1,080,000
Weighted Average Price per MMBtu	$2.88	$2.88	$2.88	$2.88	$2.88

Crude Oil

	March 31	June 30	September 30	December 31	Total Year
2015					
Swaps - Bbls	—	—	—	60,000	60,000
Weighted Average Price per Bbl	$—	$—	$—	$75.95	$75.95
2016					
Swaps - Bbls	39,000	39,000	36,000	36,000	150,000
Weighted Average Price per Bbl	$84.55	$84.55	$84.55	$84.55	$84.55
2017					
Swaps - Bbls	12,000	12,000	12,000	12,000	48,000
Weighted Average Price per Bbl	$52.50	$53.39	$54.20	$55.12	$53.80

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

	September 30, 2015	December 31, 2014	September 30, 2014
Net derivative (liabilities) assets	$10,797	$14,684	$515
Cash collateral offset in Derivatives	(10,797)	(14,684)	(515)
Cash Collateral included in Other current assets	3,556	4,392	3,766
Net asset (liability) position	$3,556	$4,392	$3,766

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. Further details of the swap agreements are set forth in Note 8 of the Notes to Consolidated Financial Statements in our 2014 Annual Report on Form 10-K/A and in Note 10 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

	September 30, 2015		December 31, 2014		September 30, 2014	
	Designated Interest Rate Swaps [a]		Designated Interest Rate Swaps [a]		Designated Interest Rate Swaps [a]	
Notional	$75,000		$75,000		$75,000	
Weighted average fixed interest rate	4.97	%	4.97	%	4.97	%
Maximum terms in years	1.33		2.00		2.25	
Derivative liabilities, current	$3,312		$3,340		$3,397	
Derivative liabilities, non-current	$722		$2,680		$3,273	
Pre-tax accumulated other comprehensive income (loss)	$(4,034	)	$(6,020	)	$(6,670	)

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

Based on September 30, 2015 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.3 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.

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ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of September 30, 2015. Based on their evaluation, they have concluded that our disclosure controls and procedures were not effective at September 30, 2015.

Management has determined that a deficiency in internal control existed due to a deficiency in the level of training in performing the control over the full cost ceiling test write down impairment calculation, specifically related to evaluating and correctly accounting for the treatment of tax amounts associated with the calculation. Management concluded that this deficiency represented a material weakness, as defined by Securities and Exchange Commission regulations.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2015, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, except as noted below.

In response to the identified material weakness, management reviewed the process and controls surrounding the oil and gas ceiling test impairment calculation. Management, with oversight from our Audit Committee, developed and implemented a plan of remediation that includes changes to processes to prevent or detect similar future occurrences. As a result of this plan, the following control remediation steps have been taken:

- Employees involved with preparation and review of the ceiling test calculation have been trained to reinforce the understanding of the requirements associated with appropriately performing this calculation, particularly as it relates to deferred taxes.

- The model used to calculate the ceiling test has been updated and refined to ensure the appropriate application of accounting for all components is embedded within the model.

- We engaged an external consultant with experience in the Oil and Gas industry to assist in reviewing the ceiling test model in consideration of the risk associated with market or business changes.

While we concluded our internal controls surrounding the oil and gas ceiling test calculation were not effective as of September 30, 2015, Management believes the steps taken have effectively remediated the material weakness. Confirmation of remediation and removal of the material weakness are dependent upon the controls operating effectively over time and Management’s assessment of internal control over financial reporting as of December 31, 2015.

During the third quarter of 2015 the Company implemented two new financial systems used to account for our gas supply transactions and Oil and Gas accounting. Although some financial processes were changed, the underlying internal controls did not materially change. The new systems were implemented to improve management reporting and were not implemented in response to any actual or perceived significant deficiencies in the Company's internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2014 Annual Report on Form 10-K/A and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Other than as set forth below, there are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2014 Annual Report on Form 10-K.

Risks Related to Our Pending Acquisition of SourceGas

The SourceGas acquisition may not be completed or may be approved subject to unfavorable regulatory conditions, which could adversely affect anticipated benefits for our business, financial condition, results of operations or stock price.

On July 12, 2015, Black Hills Utility Holdings entered in the Purchase and Sale Agreement to acquire SourceGas (the "Transaction"). We expect to complete the Transaction in the first half of 2016, subject to customary closing conditions, including regulatory approval from Arkansas Public Service Commission, Colorado Public Utilities Commission, Nebraska Public Service Commission and Wyoming Public Service Commission. The Purchase and Sale Agreement requires us to use our reasonable best efforts to obtain these approvals. Such closing conditions and approvals may take longer than anticipated to satisfy, which could delay the closing of the Transaction, and we cannot provide assurances that all closing conditions will be satisfied or waived or that we will obtain all required approvals.

The regulatory commissions or interveners in the approval proceedings could seek to block or challenge the Transaction or one or more regulatory commissions could impose restrictions or require changes to the terms of the Transaction they deem necessary or desirable in the public interest as a condition to approving the Transaction, including restrictions on the business, operations, or financial performance of our utilities and the utilities we would acquire from SourceGas. Any such challenges could delay the closing of the Transaction. If these approvals are not received, then we will not be obligated to complete the Transaction. If these approvals are not received, or are not received on terms that satisfy the conditions set forth in the Purchase and Sale Agreement, then the sellers will not be obligated to complete the Transaction. However, if these approvals include restrictions or require changes to the terms of the Transaction, we may be required to complete the Transaction subject to such restrictions and changed terms, which could materially and adversely affect our business results and financial condition.

The waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, was terminated early on August 18, 2015.

The Purchase and Sale Agreement contains certain termination rights for both us and the sellers, including, among others, the right to terminate if the Transaction is not completed by July 12, 2016 (subject to extension to October 12, 2016, under certain circumstances related to fulfillment of the regulatory approval closing conditions).

The Transaction may not achieve its intended results, including anticipated operating efficiencies and cost savings, and integration efforts may adversely affect our business, financial condition or results of operations, which may negatively affect the market price of our common stock.

While management currently anticipates that the Transaction will be accretive to our earnings per share (as adjusted) (Non-GAAP) beginning in the first calendar year after closing of the Transaction, this expectation is based on preliminary estimates which may materially change. In addition, although we expect that the Transaction will result in various other benefits, including a significant amount of operating efficiencies and other financial and operational benefits, there can be no assurance regarding when or the extent to which we will be able to realize these operating efficiencies or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the businesses acquired can be operated in the manner we intend and whether our costs to finance the acquisition will be consistent with our expectations. Events outside of our control, including but not limited to regulatory changes or developments, could also adversely affect our ability to realize the anticipated benefits from the acquisition. Thus the integration of SourceGas's business may be unpredictable, subject to delays or changed circumstances, and we can give no assurance that the acquired businesses will perform in accordance with our expectations or that our expectations with respect to integration or operating efficiencies as a result of the acquisition will materialize. In addition, our anticipated transaction costs and costs to achieve the integration of SourceGas may differ significantly from our current estimates. The integration may place an additional burden on our management and internal resources, and the diversion of management's attention during the integration process could have an adverse effect on our business, financial condition and expected operating results. Any of these factors could cause a decrease in the price of our common stock.

The Transaction may subject us to other risks.

The Transaction subjects us to a number of additional risks, including the following:

- Uncertainty about the effect of the Transaction on employees, customers, vendors and others may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the Transaction is completed, and for a period of time thereafter, and could cause vendors and others that deal with us to seek to change existing business relationships.

- The trading price of our common stock may decline to the extent that the current market price reflects a market assumption that the Transaction will be completed.

- While the Transaction is pending, we are subject to business uncertainties that could materially adversely affect our financial results.

- After review of the Transaction announcement, our issuer credit ratings were updated on July 13, 2015 and July 14, 2015, respectively, by Standard & Poor's ("S&P"), Moody's and Fitch. Our credit rating is BBB with stable outlook by S&P, Baa1 with negative outlook by Moody's and BBB+ with negative outlook by Fitch. We cannot be assured that our credit ratings will not be lowered as a result of the proposed Transaction or for any other reason, including the failure to consummate the Transaction. Any reduction in our credit ratings could adversely affect our ability to complete the Transaction, our access to capital, our cost of capital and our other operating costs, and our ability to refinance or repay our existing debt and complete new financings, including permanent financing of the Transaction on acceptable terms or at all.

- U.S. credit markets may impact our ability to execute our plan in securing permanent financing for the Transaction on favorable terms. We expect to pay the majority of the purchase price of the Transaction with a combination of debt and equity financing. Unexpected periods of volatility and disruption in U.S. credit markets could affect our ability to obtain permanent financing for the Transaction more difficult and costly. Unexpected volatility on utility stock indexes could also have an unfavorable impact on our stock price, which could affect our ability to raise equity on favorable terms.

The occurrence of any of these events individually or in combination could have a material adverse effect on our business, financial condition or results of operations or the trading price of our common stock.

We expect to issue significant debt, common stock and equity-linked securities to provide permanent financing for the Transaction in lieu of or to refund borrowings under the Bridge Term Loan Agreement and, as a result, we are subject to market risks including market demand for debt and equity offerings, interest rate volatility, and adverse impacts on our credit ratings.

On August 6, 2015, we entered into the Bridge Term Loan Agreement for commitments totaling $1.17 billion, which may be used to finance all or a significant portion of the Transaction and pay related fees and expenses in the event that permanent financing is not completed at the time of the closing. We expect to pay the majority of the purchase price of the Transaction with a combination of debt and equity financing. As a result, it is anticipated that our debt will materially increase in connection with the Transaction.

Although we and our advisers believe we have taken prudent steps to position the Company and its subsidiaries for successful capital raises, there can be no assurance as to the ultimate cost or availability of funds to complete the permanent financing.

Among other risks, the planned increase in indebtedness may:

- make it more difficult for us to repay or refinance our debts as they become due during adverse economic and industry conditions;
- limit our flexibility to pursue other strategic opportunities or react to changes in our business and the industry in which we operate and, consequently, place us at a competitive disadvantage to competitors with less debt;
- require an increased portion of our cash flows from operations to be used for debt service payments, thereby reducing the availability of cash flows to fund working capital, capital expenditures, dividend payments and other general corporate purposes;
- result in a downgrade in the credit rating of our indebtedness, which could limit our ability to borrow additional funds or increase the interest rates applicable to our indebtedness;
- result in higher interest expense in the event of increases in market interest rates for both long-term debt as well as short-term commercial paper, bank loans or borrowings under our line of credit at variable rates;
- reduce the amount of credit available to support hedging activities; and
- require that additional terms, conditions or covenants be placed on us.

Among other risks, the issuance of additional equity pursuant to offerings of such securities may:

- be dilutive to our existing shareholders and earnings per share;
- impact our capital structure and cost of the capital;
- be adversely impacted by movements in the overall equity markets or the utility or natural gas utility industry sectors of that market, which could impact the offering price of our new equity or necessitate the use of other equity or equity-like instruments such as preferred stock, convertible preferred shares, or convertible debt; and
- impact our ability to make our current and future dividend payments.

We will incur significant transaction and acquisition-related costs in connection with the Transaction.

We expect to incur significant costs associated with the Transaction and combining the operations of the two companies, including costs to achieve targeted cost-savings. The substantial majority of the expenses resulting from the Transaction will be composed of transaction costs, systems consolidation costs, and business integration and employment-related costs. We may also incur transaction fees and costs related to formulating integration plans.

Additional unanticipated costs may be incurred in the integration of the two companies' businesses. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow us to offset incremental transaction and acquisition-related costs over time, this net benefit may not be achieved in the near term, or at all.

Failure to complete the Transaction could negatively affect our stock price as well as our future business and financial results.

If the Transaction is not completed, we will be subject to a number of risks, including:

- we must pay costs related to the Transaction and related financings, including legal, accounting, financial advisory, filing and printing costs, whether the Transaction is completed or not;

- we could be subject to litigation related to the failure to complete the Transaction or other factors, which litigation may adversely affect our business, financial results and stock price; and

- if we finance the Transaction with common stock and equity-linked securities, we could be subject to significant earnings per share dilution if we do not find other attractive investment opportunities or undertake other means to reduce our overall shares outstanding.

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

There were no unregistered securities sold during the nine months ended September 30, 2015.

ITEM 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Quarterly Report on Form 10-Q.

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K file on July 14, 2015).
Exhibit 2.2*	Option Agreement by and among Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K file on July 14, 2015).
Exhibit 2.3*	Guaranty of Black Hills Corporation in favor of Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, dated as of July 12, 2015 (filed as Exhibit 2.3 to the Registrant's Form 8-K file on July 14, 2015).
Exhibit 3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant’s Form 10-K for 2004).
Exhibit 3.2*	

	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010).
Exhibit 4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).

Exhibit 4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
Exhibit 10.1*	Bridge Term Loan Agreement dated as of August 6, 2015 among Black Hills Corporation, as Borrower, the Financial Institutions party thereto, as Banks, and Credit Suisse AG, Cayman Island Branch, as administrative agent, and Credit Suisse Securities (USA) LLC, as Sole Lead Arranger and Sole Bookrunner (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on August 12, 2015).
Exhibit 10.2*	First Amendment dated August 6, 2015 to Credit Agreement dated April 13, 2015 among Black Hills Corporation, as Borrower, JPMorgan Chase Bank, N.A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on August 12, 2015).
Exhibit 10.3*	Second Amendment dated August 6, 2015 to Amended and Restated Credit Agreement dated May 29, 2014 among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on August 12, 2015).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	

	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

*Previously filed as part of the filing indicated and incorporated by reference herein.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BLACK HILLS CORPORATION

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

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

Dated: November 4, 2015

INDEX TO EXHIBITS

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Exhibit 3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant’s Form 8-K filed on February 3, 2010).
Exhibit 4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant’s Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to the Registrant’s Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrants’ Form 8-K filed on November 18, 2013).
Exhibit 4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant’s Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant’s Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant’s Post-Effective Amendment No. 2 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on October 2, 2014).
Exhibit 4.3*	

	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
Exhibit 10.1*	Bridge Term Loan Agreement dated as of August 6, 2015 among Black Hills Corporation, as Borrower, the Financial Institutions party thereto, as Banks, and Credit Suisse AG, Cayman Island Branch, as administrative agent, and Credit Suisse Securities (USA) LLC, as Sole Lead Arranger and Sole Bookrunner (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on August 12, 2015).

Exhibit 10.2*	First Amendment dated August 6, 2015 to Credit Agreement dated April 13, 2015 among Black Hills Corporation, as Borrower, JPMorgan Chase Bank, N.A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on August 12, 2015).
Exhibit 10.3*	Second Amendment dated August 6, 2015 to Amended and Restated Credit Agreement dated May 29, 2014 among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on August 12, 2015).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

*Previously filed as part of the filing indicated and incorporated by reference herein.