BLACK HILLS CORP /SD/
Form 10-Q
August 07, 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 June 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 July 31, 2015	
Common stock, $1.00 par value	44,834,944	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.
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 announced in 2014 and closed on July 1, 2015.
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse Gases

GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of natural gas and certain services through to customers.
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 announced in 2014 that closed on January 1, 2015.
MMBtu	Million British thermal units
Moody’s	Moody’s Investors Service, Inc.
MW	Megawatts
MWh	Megawatt-hours
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
PPA	Power Purchase Agreement
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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in thousands, except per share amounts)			
Revenue	$272,254	$283,237	$714,241	$743,406
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of natural gas sold	73,824	101,331	279,151	331,799
Operations and maintenance	67,264	66,074	138,348	137,301
Non-regulated energy operations and maintenance	23,146	21,350	45,196	43,682
Depreciation, depletion and amortization	40,051	35,877	79,053	71,126
Taxes - property, production and severance	11,377	11,044	23,313	21,380
Impairment of long-lived assets	94,484	—	116,520	—
Other operating expenses	966	149	1,018	274
Total operating expenses	311,112	235,825	682,599	605,562
Operating income (loss)	(38,858)	47,412	31,642	137,844
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(19,545)	(17,886)	(39,455)	(35,746)
Allowance for funds used during construction - borrowed	207	256	365	526
Capitalized interest	481	246	757	503
Interest income	301	576	749	966
Allowance for funds used during construction - equity	77	293	133	531
Other income (expense), net	395	409	726	1,000
Total other income (expense), net	(18,084)	(16,106)	(36,725)	(32,220)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	(56,942)	31,306	(5,083)	105,624
Equity in earnings (loss) of unconsolidated subsidiaries	(47)	—	(344)	—
Impairment of equity investments	(5,170)	—	(5,170)	—
Income tax benefit (expense)	20,317	(10,959)	2,605	(36,632)
Net income (loss) available for common stock	$(41,842)	$20,347	$(7,992)	$68,992
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic	$(0.94)	$0.46	$(0.18)	$1.56
Earnings (loss) per share, Diluted	$(0.94)	$0.46	$(0.18)	$1.55
Weighted average common shares outstanding:				
Basic	44,617	44,399	44,579	44,365
Diluted	44,617	44,588	44,579	44,571

Dividends declared per share of common stock	$0.405	$0.390	$0.810	$0.780

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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(in thousands)			
Net income (loss) available for common stock	$(41,842)	$20,347	$(7,992)	$68,992
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $1,171and $1,115 for the three months ended 2015 and 2014 and $128 and $2,422 for the six months ended 2015 and 2014, respectively)	(1,966)	(1,959)	(130)	(4,216)
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $735 and $(774) for the three months ended 2015 and 2014 and $1,989 and $(1,199) for the six months ended 2015 and 2014, respectively)	(1,261)	1,403	(2,502)	2,183
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 $15 and $2 for the six months ended 2015 and 2014, respectively)	—	—	(27)	(2)
Benefit plan liability tax adjustments - net gain (loss)	—	(394)	—	(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 six months ended 2015 and 2014, respectively)	—	—	—	164
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $19 and $39 for the three months ended 2015 and 2014 and $38 and $43 for the six months ended 2015 and 2014, respectively)	(36)	(70)	(72)	(79)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(247) and $(91) for the three months ended 2015 and 2014 and $(494) and $(176) for the six months ended 2015 and 2014, respectively)	458	168	916	325
Other comprehensive income (loss), net of tax	(2,805)	(852)	(1,815)	(2,019)
Comprehensive income (loss) available for common stock	$(44,647)	$19,495	$(9,807)	$66,973

See Note 12 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 June 30, 2015	December 31, 2014	June 30, 2014
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$87,210	$21,218	$14,697
Restricted cash and equivalents	2,316	2,056	2
Accounts receivable, net	123,661	189,992	135,145
Materials, supplies and fuel	73,749	91,191	81,164
Derivative assets, current	—	—	1,737
Income tax receivable, net	770	2,053	1,043
Deferred income tax assets, net, current	52,394	48,288	23,872
Regulatory assets, current	47,157	74,396	64,735
Other current assets	51,315	24,842	21,660
Total current assets	438,572	454,036	344,055
Investments	12,098	17,294	17,096
Property, plant and equipment	4,726,478	4,563,400	4,408,291
Less: accumulated depreciation and depletion	(1,522,969)	(1,357,929)	(1,361,233)
Total property, plant and equipment, net	3,203,509	3,205,471	3,047,058
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,211	3,176	3,286
Regulatory assets, non-current	180,815	183,443	138,226
Other assets, non-current	28,670	29,086	31,808
Total other assets, non-current	566,092	569,101	526,716
TOTAL ASSETS	$4,220,271	$4,245,902	$3,934,925

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 June 30, 2015	December 31, 2014	June 30, 2014
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$78,021	$124,139	$100,098
Accrued liabilities	160,528	170,115	141,177
Derivative liabilities, current	3,289	3,340	3,480
Regulatory liabilities, current	10,910	3,687	828
Notes payable	105,760	75,000	132,700
Current maturities of long-term debt	—	275,000	275,000
Total current liabilities	358,508	651,281	653,283
Long-term debt, net of current maturities	1,567,727	1,267,589	1,121,950
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	510,435	511,952	463,680
Derivative liabilities, non-current	1,433	2,680	4,251
Regulatory liabilities, non-current	150,835	145,144	119,462
Benefit plan liabilities	165,791	158,966	116,403
Other deferred credits and other liabilities	154,656	154,406	137,765
Total deferred credits and other liabilities	983,150	973,148	841,561
Commitments and contingencies (See Notes 2, 8, 9, 14, 15)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,871,771; 44,714,072; and 44,682,885 shares, respectively	44,872	44,714	44,683
Additional paid-in capital	751,679	748,840	744,505
Retained earnings	532,965	577,249	550,185
Treasury stock, at cost – 35,855; 42,226; and 40,951 shares, respectively	(1,771)	(1,875)	(1,801)
Accumulated other comprehensive income (loss)	(16,859)	(15,044)	(19,441)
Total stockholders' equity	1,310,886	1,353,884	1,318,131
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,220,271	$4,245,902	$3,934,925

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 STATEMENTS OF CASH FLOWS

(unaudited)	Six Months Ended June 30,	
	2015	2014
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$(7,992)	$68,992
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	79,053	71,126
Deferred financing cost amortization	1,119	1,107
Impairment of long-lived assets	121,690	—
Derivative fair value adjustments	(5,249)	(1,660)
Stock compensation	3,098	6,908
Deferred income taxes	(6,277)	36,129
Employee benefit plans	10,467	7,409
Other adjustments, net	3,720	1,481
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	20,218	7,314
Accounts receivable, unbilled revenues and other operating assets	63,172	47,598
Accounts payable and other operating liabilities	(66,294)	(24,978)
Regulatory assets - current	27,178	(43,604)
Regulatory liabilities - current	7,290	(9,845)
Other operating activities, net	3,215	5,858
Net cash provided by (used in) operating activities	254,408	173,835
Investing activities:		
Property, plant and equipment additions	(206,472)	(177,302)
Other investing activities	(652)	(2,994)
Net cash provided by (used in) investing activities	(207,124)	(180,296)
Financing activities:		
Dividends paid on common stock	(36,292)	(34,803)
Common stock issued	1,702	1,693
Short-term borrowings - issuances	154,460	214,100
Short-term borrowings - repayments	(123,700)	(163,900)
Long-term debt - issuances	300,000	—
Long-term debt - repayments	(275,000)	—
Other financing activities	(2,462)	(3,773)
Net cash provided by (used in) financing activities	18,708	13,317
Net change in cash and cash equivalents	65,992	6,856
Cash and cash equivalents, beginning of period	21,218	7,841
Cash and cash equivalents, end of period	$87,210	$14,697

See Note 13 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 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 June 30, 2015, December 31, 2014, and June 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 price. 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 six months ended June 30, 2015 and June 30, 2014, and our financial condition as of June 30, 2015, December 31, 2014, and June 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 the 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 noncash 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 June 30, 2014			For the Six Months Ended June 30, 2014		
	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
	(in thousands expect per share amounts)					
Depreciation, depletion and amortization	$36,712	$(835)	$35,877	$72,795	$(1,669)	$71,126
Total operating expenses	$236,660	$(835)	$235,825	$607,231	$(1,669)	$605,562
Operating income (loss)	$46,577	$835	$47,412	$136,175	$1,669	$137,844
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	$30,471	$835	$31,306	$103,955	$1,669	$105,624
Income tax benefit (expense)	$(10,651)	$(308)	$(10,959)	$(36,017)	$(615)	$(36,632)
Net income (loss) available for common stock	$19,820	$527	$20,347	$67,938	$1,054	$68,992

Earnings (loss) per share of common stock:						
Earnings (loss) per share, Basic	$0.45	$ 0.01	$0.46	$1.53	$0.03	$1.56
Earnings (loss) per share, Diluted	$0.44	$ 0.02	$0.46	$1.52	$0.03	$1.55

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CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the Three Months Ended June 30, 2014			For the Six Months Ended June 30, 2014		
(in thousands)	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
Net income (loss) available for common stock	$19,820	$527	$20,347	$67,938	$1,054	$68,992
Comprehensive income (loss)	$18,968	$527	$19,495	$65,919	$1,054	$66,973

CONDENSED CONSOLIDATED BALANCE SHEET

	As of June 30, 2014		
	As Reported	Adjustments	As Revised
	(in thousands)		
Accumulated depreciation and depletion	$(1,325,660)	$(35,573)	$(1,361,233)
Total property, plant and equipment, net	$3,082,631	$(35,573)	$3,047,058
TOTAL ASSETS	$3,970,498	$(35,573)	$3,934,925
Deferred income tax liability, non-current	$476,059	$(12,379)	$463,680
Total deferred credits and other liabilities	$853,940	$(12,379)	$841,561
Retained earnings	$573,379	$(23,194)	$550,185
Total stockholders' equity	$1,341,325	$(23,194)	$1,318,131
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,970,498	$(35,573)	$3,934,925

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2014		
	As Reported	Adjustments	As Revised
	(in thousands)		
Net income (loss) available for common stock	$67,938	$1,054	$68,992
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	$72,795	$(1,669)	$71,126
Deferred income taxes	$35,514	$615	$36,129
Net cash provided by (used in) operating activities	$173,835	$—	$173,835

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

(2) SUBSEQUENT EVENT

Acquisition of SourceGas

On July 12, 2015, Black Hills Utility Holdings entered in 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 $720 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 tax benefits consisting of acquired NOLs and goodwill tax benefits 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 have entered into a commitment letter for a one-year, $1.17 billion senior unsecured fully committed bridge facility to be provided by Credit Suisse.

We expect to finance the acquisition with the aforementioned $720 million of assumed debt, $450 million to $550 million of new debt, $575 million to $675 million of equity and equity-linked securities, and the remainder with cash on hand and Revolver draws.

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 is also subject to notification, clearance and reporting requirements under the Hart-Scott-Rodino Act. 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 6th, 2015, we entered into a Bridge Term Loan Agreement with Credit Suisse as the Administrate Agent and 10 additional banks, collectively, for commitments totaling $1.17 billion billion pursuant to the previously executed bridge commitment letter with Credit Suisse.   We may draw up to $1.17 billion 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 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 Loan Credit 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 billion and less than $1.46 billion 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 June 30, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$169,751	$2,509	$17,702
Gas	79,426	—	3,165
Non-regulated Energy:			
Power Generation	1,706	20,603	7,549
Coal Mining	9,052	7,673	3,049
Oil and Gas [(a)(b)]	12,319	—	(71,195)
Corporate activities [(c)]	—	—	(2,112)
Inter-company eliminations	—	(30,785)	—
Total	$272,254	$—	$(41,842)

Three Months Ended June 30, 2014	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$158,740	$3,144	$11,427
Gas	102,499	—	1,994
Non-regulated Energy:			
Power Generation	1,267	20,713	7,194
Coal Mining	5,583	9,068	2,016
Oil and Gas	15,148	—	(1,133)
Corporate activities	—	—	(1,151)
Inter-company eliminations	—	(32,925)	—
Total	$283,237	$—	$20,347

Six Months Ended June 30, 2015	External Operating Revenues	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$352,725	$5,933	$36,631
Gas	317,077	—	25,377
Non-regulated Energy:			
Power Generation	3,659	41,324	15,694
Coal Mining	17,194	15,465	6,059
Oil and Gas [(a)(b)]	23,586	—	(90,310)
Corporate activities [(c)]	—	—	(1,443)
Inter-company eliminations	—	(62,722)	—
Total	$714,241	$—	$(7,992)

Six Months Ended June 30, 2014	External Operating Revenues	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$336,835	$7,151	$26,002
Gas	361,836	—	26,692
Non-regulated Energy:			
Power Generation	2,536	41,792	15,267
Coal Mining	12,201	17,948	4,480
Oil and Gas	29,998	—	(2,628)
Corporate activities	—	—	(821)
Inter-company eliminations	—	(66,891)	—
Total	$743,406	$—	$68,992

(a) Net income (loss) for the three and six months ended June 30, 2015 included non-cash after-tax ceiling test impairments of $63 million and $77 million, respectively. See Note 16 to the Condensed Consolidated Financial statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) for the three and six months ended June 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 16 to the Condensed Consolidated Financial statements in this Quarterly Report on Form 10-Q.

(c) Net income (loss) for the three and six months ended June 30, 2015 included acquisition costs, net of tax of $0.5 million and $0.3 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:	June 30, 2015	December 31, 2014	June 30, 2014
Utilities:			
Electric [(a)]	$2,856,903	$2,748,680	$2,603,900
Gas	801,295	906,922	799,365
Non-regulated Energy:			
Power Generation [(a)]	72,270	76,945	85,269
Coal Mining	76,079	74,407	73,701
Oil and Gas [(b)] [(c)]	275,068	332,343	272,264
Corporate activities	138,656	106,605	100,426
Total assets	$4,220,271	$4,245,902	$3,934,925

(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 $94 million and $117 million for the for the three and six months ended June 30, 2015, respectively. See Note 16 to the Condensed Consolidated Financial statements in this Quarterly Report on Form 10-Q.

(c) Includes a noncash impairment of our Oil and Gas equity investments of $5.2 million for the three and six months ended June 30, 2015.

(4) ACCOUNTS RECEIVABLE

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

June 30, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$46,381	$33,501	$(685)	$79,197
Gas Utilities	25,635	9,418	(1,259)	33,794
Power Generation	1,199	—	—	1,199
Coal Mining	3,402	—	—	3,402
Oil and Gas	5,099	—	(13)	5,086
Corporate	983	—	—	983
Total	$82,699	$42,919	$(1,957)	$123,661

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

June 30, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$48,333	$21,716	$(622)	$69,427
Gas Utilities	43,104	9,265	(1,027)	51,342
Power Generation	1,388	—	—	1,388
Coal Mining	1,866	—	—	1,866
Oil and Gas	9,123	—	(13)	9,110
Corporate	2,012	—	—	2,012
Total	$105,826	$30,981	$(1,662)	$135,145

(5) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of June 30, 2015	As of December 31, 2014	As of June 30, 2014
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a) (d)]	1	$26,862	$23,820	$29,605
Deferred gas cost adjustments [(a)(d)]	2	5,588	37,471	35,479
Gas price derivatives [(a)]	7	17,907	18,740	3,561
AFUDC [(b)]	45	12,321	12,358	12,468
Employee benefit plans [(c) (e)]	12	96,734	97,126	65,874
Environmental [(a)]	subject to approval	1,224	1,314	1,314
Asset retirement obligations [(a)]	44	3,242	3,287	3,278
Bond issue cost [(a)]	23	3,204	3,276	3,347
Renewable energy standard adjustment [(a)]	5	5,629	9,622	14,501
Flow through accounting [(c)]	35	27,861	25,887	22,754
Decommissioning costs [(f)]	10	14,845	12,484	—
Other regulatory assets [(a)]	15	12,555	12,454	10,780
		$227,972	$257,839	$202,961
Regulatory liabilities				
Deferred energy and gas costs [(a) (d)]	1	$16,114	$6,496	$6,490
Employee benefit plans [(c) (e)]	12	53,163	53,139	34,356
Cost of removal [(a)]	44	84,118	78,249	70,841
Other regulatory liabilities [(c)]	25	8,350	10,947	8,603
		$161,745	$148,831	$120,290

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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 June 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 $12 million of decommissioning costs associated with the retirements of the Neil Simpson I and Ben French power plants that are allowed a rate of return, in addition to recovery of costs.

(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:

	June 30, 2015	December 31, 2014	June 30, 2014
Materials and supplies	$54,646	$49,555	$51,925
Fuel - Electric Utilities	6,644	6,637	7,679
Natural gas in storage held for distribution	12,459	34,999	21,560
Total materials, supplies and fuel	$73,749	$91,191	$81,164

(7) 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss) available for common stock	$(41,842)	$20,347	$(7,992)	$68,992
Weighted average shares - basic	44,617	44,399	44,579	44,365
Dilutive effect of:				
Equity compensation	—	189	—	206
Weighted average shares - diluted	44,617	44,588	44,579	44,571

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive.

Due to our net loss the for the three and six months ended June 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, 83,613 and 101,146 equity compensation shares were excluded from the computations for the three and six months ended June 30, 2015, respectively.

In addition to these potentially dilutive shares excluded due to our net loss for the three and six months ended June 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Equity compensation	119	81	113	63
Anti-dilutive shares	119	81	113	63

(8) 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:

	June 30, 2015		December 31, 2014		June 30, 2014	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$105,760	$23,100	$75,000	$35,000	$132,700	$20,272

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 June 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 June 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

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

	As of June 30, 2015	Covenant Requirement	
Recourse Leverage Ratio	57%	Less than	65%

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

(9) 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 10.

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:

	June 30, 2015		December 31, 2014		June 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)]	276,000	4,187,500	334,500	6,582,500	424,500	9,265,000
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 June 30, 2015 prices, a $6.4 million gain would be reclassified from AOCI over 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:

	June 30, 2015		December 31, 2014		June 30, 2014	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	17,270,000	66	19,370,000	72	16,240,000	78
Natural gas options purchased	3,980,000	9	4,020,000	8	3,980,000	9
Natural gas basis swaps purchased	14,445,000	54	12,005,000	60	13,415,000	66

(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):

	June 30, 2015	December 31, 2014	June 30, 2014
Derivative assets, current	$—	$—	$1,737
Derivative assets, non-current	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$17,907	$18,740	$3,561

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:

	June 30, 2015 Interest Rate Swaps [(a)]		December 31, 2014 Interest Rate Swaps [(a)]		June 30, 2014 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	1.50		2.00		2.50	
Derivative liabilities, current	$3,289		$3,340		$3,480	
Derivative liabilities, non-current	$1,433		$2,680		$4,251	

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(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 June 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 June 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	$(892	)	Interest expense	$(1,670	)		$—
Commodity derivatives	(2,245	)	Revenue	3,666			—
Total	$(3,137	)		$1,996			$—

Three Months Ended June 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	$(337	)	Interest expense	$(926	)		$—
Commodity derivatives	(2,737	)	Revenue	(1,251	)		—
Total	$(3,074	)		$(2,177	)		$—

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Six Months Ended June 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	$(1,778)	Interest expense	$(3,107)		$—
Commodity derivatives	1,520	Revenue	7,598		—
Total	$(258)		$4,491		$—

Six Months Ended June 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	$(429)	Interest expense	$(1,820)		$—
Commodity derivatives	(6,209)	Revenue	(1,562)		—
Total	$(6,638)		$(3,382)		$—

(10) 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 as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments. A discussion of fair value of financial instruments is included in Note 11:

	As of June 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	—	5,178	—	(5,178)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	4,372	—	(4,372)	—
Commodity derivatives — Utilities	—	2,577	—	(2,577)	—
Total	$—	$12,127	$—	$(12,127)	$—
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	112	—	(112)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	498	—	(498)	—
Commodity derivatives — Utilities	—	18,758	—	(18,758)	—

Interest rate swaps	—	4,722	—	—	4,722
Total	$—	$24,090	$—	$(19,368)	$4,722

	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 June 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	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	600	—	(600)	—
Commodity derivatives — Utilities	—	4,342	—	(2,605)	1,737
Total	$—	$4,942	$—	$(3,205)	$1,737
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	4,020	—	(4,020)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	2,030	—	(2,030)	—
Commodity derivatives — Utilities	—	5,989	—	(5,989)	—
Interest rate swaps	—	7,731	—	—	7,731
Total	$—	$19,770	$—	$(12,039)	$7,731

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 June 30, 2015, December 31, 2014, and June 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 9.

The following tables present the fair value and balance sheet classification of our derivative instruments (in thousands):
As of June 30, 2015

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$6,931	$—
Commodity derivatives	Derivative assets — non-current	2,619	—
Commodity derivatives	Derivative liabilities — current	—	493
Commodity derivatives	Derivative liabilities — non-current	—	117
Interest rate swaps	Derivative liabilities — current	—	3,289
Interest rate swaps	Derivative liabilities — non-current	—	1,433
Total derivatives designated as hedges		$9,550	$5,332
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	5,156
Commodity derivatives	Derivative liabilities — non-current	—	11,025
Total derivatives not designated as hedges		$—	$16,181

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 June 30, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$262	$—
Commodity derivatives	Derivative assets — non-current	338	—
Commodity derivatives	Derivative liabilities — current	—	3,702
Commodity derivatives	Derivative liabilities — non-current	—	2,348
Interest rate swaps	Derivative liabilities — current	—	3,480
Interest rate swaps	Derivative liabilities — non-current	—	4,251
Total derivatives designated as hedges		$600	$13,781
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,737	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	3,384
Total derivatives not designated as hedges		$1,737	$3,384

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 10, were as follows (in thousands) as of:

	June 30, 2015		December 31, 2014		June 30, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$87,210	$87,210	$21,218	$21,218	$14,697	$14,697
Restricted cash and equivalents [(a)]	$2,316	$2,316	$2,056	$2,056	$2	$2
Notes payable [(a)]	$105,760	$105,760	$75,000	$75,000	$132,700	$132,700
Long-term debt, including current maturities [(b)]	$1,567,727	$1,700,487	$1,542,589	$1,734,555	$1,396,950	$1,578,756

(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.

(12) 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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Gains (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$1,670	$926	$3,107	$1,820
Commodity contracts	Revenue	(3,666)	1,251	(7,598)	1,562
		(1,996)	2,177	(4,491)	3,382
Income tax	Income tax benefit (expense)	735	(774)	1,989	(1,199)
Reclassification adjustments related to cash flow hedges, net of tax		$(1,261)	$1,403	$(2,502)	$2,183
Amortization of defined benefit plans:					
Prior service cost	Utilities - Operations and maintenance	$(26)	$(25)	$(53)	$(51)
	Non-regulated energy operations and maintenance	(29)	(84)	(57)	(71)
Actuarial gain (loss)	Utilities - Operations and maintenance	454	158	908	315

	Non-regulated energy operations and maintenance	251	101	502	186
		650	150	1,300	379
Income tax	Income tax benefit (expense)	(228)	(52)	(456)	(133)
Reclassification adjustments related to defined benefit plans, net of tax		$422	$98	$844	$246

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)
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)

(13) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six months ended	June 30, 2015	June 30, 2014
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$36,661	$40,611
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)	$(37,698)	$(35,009)
Income taxes, net	$(1,202)	$(396)

(14) 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Service cost	$1,494	$1,362	$2,988	$2,724
Interest cost	3,880	3,963	7,760	7,926
Expected return on plan assets	(4,867)	(4,516)	(9,734)	(9,032)
Prior service cost	15	16	30	32
Net loss (gain)	2,759	1,201	5,518	2,403
Net periodic benefit cost	$3,281	$2,026	$6,562	$4,053

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Service cost	$464	$425	$928	$850
Interest cost	450	480	900	959
Expected return on plan assets	(33)	(21)	(66)	(42)
Prior service cost (benefit)	(107)	(107)	(214)	(214)
Net loss (gain)	102	40	204	80
Net periodic benefit cost	$876	$817	$1,752	$1,633

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Service cost	$392	$374	$883	$749
Interest cost	364	362	728	724
Prior service cost	1	1	2	1
Net loss (gain)	270	124	540	249
Net periodic benefit cost	$1,027	$861	$2,153	$1,723

Contributions

We anticipate that we will make contributions to the benefit plans during 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 June 30, 2015	Six Months Ended June 30, 2015	Anticipated for 2015	Anticipated for 2016
Defined Benefit Pension Plans	$—	$—	$10,200	$10,200
Non-pension Defined Benefit Postretirement Healthcare Plans	$939	$1,878	$1,877	$4,026
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$372	$744	$743	$1,544

(15) 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.

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 has intervened in the lawsuit. Both the private landowners and the State of Wyoming assert claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance and trespass. In addition to claims for compensatory damages, the lawsuit seeks recovery of punitive damages. We have denied and will vigorously defend all claims arising out of the fire. We cannot predict the outcome of expert investigation, the viability of alleged claims or the outcome of the litigation.

Civil litigation of this kind, however, 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 expert investigations and our review of damage claim documentation are ongoing, and there are significant factual and legal issues to be resolved. Further claims may be presented by these claimants and other parties. We have received 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. Based on the legal standard for measuring damages that we believe applies to this matter, we estimate the current total 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 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 June 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 June 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 June 30, 2015, the restricted net assets at our Utilities Group were approximately $325 million.

(16) 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.

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. 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. 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. As a result of continued low commodity prices 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.

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.

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

We are a 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 six months ended June 30, 2015 and 2014, and our financial condition as of June 30, 2015, December 31, 2014 and June 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.
See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 64.

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 June 30, 2015 Compared to Three Months Ended June 30, 2014. Net income (loss) for the three months ended June 30, 2015 was $(42) million, or $(0.94) per share, compared to Net income (loss) of $20 million, or $0.46 per share, reported for the same period in 2014. The Net income (loss) for the three months ended June 30, 2015 included a non-cash after-tax ceiling test impairment of $63 million and a non-cash after-tax impairment loss on an equity investment of $3.4 million. The Net income (loss) for the three months ended June 30, 2014 did not contain any expenses, gains or losses that we believe are not representative of our core operating performance.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014. Net income (loss) for the six months ended June 30, 2015 was $(8) million, or $(0.18) per share, compared to Net income (loss) of $69 million, or $1.55 per share, reported for the same period in 2014. The Net income (loss) for the six months ended June 30, 2015 included a non-cash after-tax ceiling test impairment of $77 million and a non-cash after-tax impairment loss on an equity investment of $3.4 million. The Net income (loss) for the six months ended June 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 June 30,			Six Months Ended June 30,		
	2015	2014	Variance	2015	2014	Variance
Revenue						
Utilities	$251,686	$264,383	$(12,697)	$675,735	$705,822	$(30,087)
Non-regulated Energy	51,353	51,779	(426)	101,228	104,475	(3,247)
Inter-company eliminations	(30,785)	(32,925)	2,140	(62,722)	(66,891)	4,169
	$272,254	$283,237	$(10,983)	$714,241	$743,406	$(29,165)
Net income (loss)						
Electric Utilities	$17,702	$11,427	$6,275	$36,631	$26,002	$10,629
Gas Utilities	3,165	1,994	1,171	25,377	26,692	(1,315)
Utilities	20,867	13,421	7,446	62,008	52,694	9,314
Power Generation	7,549	7,194	355	15,694	15,267	427
Coal Mining	3,049	2,016	1,033	6,059	4,480	1,579
Oil and Gas [(a)] [(b)]	(71,195)	(1,133)	(70,062)	(90,310)	(2,628)	(87,682)
Non-regulated Energy	(60,597)	8,077	(68,674)	(68,557)	17,119	(85,676)
Corporate activities and eliminations [(c)]	(2,112)	(1,151)	(961)	(1,443)	(821)	(622)
Net income (loss)	$(41,842)	$20,347	$(62,189)	$(7,992)	$68,992	$(76,984)

(a) Net income (loss) for the three and six months ended June 30, 2015 included non-cash after-tax ceiling test impairments of $63 million and $77 million, respectively. See Note 16 of the Condensed Consolidated Financial statements in this Quarterly Report on Form 10-Q.

(b) Net income (loss) for the three and six months ended June 30, 2015 included a non-cash after-tax impairment to equity investments of $3.4 million. See Note 16 of the Condensed Consolidated Financial statements in this

Quarterly Report on Form 10-Q.
(c) Net income (loss) for the three and six months ended June 30, 2015 included acquisition costs, after-tax of $0.5 million and $0.3 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

- Gas Utilities experienced milder weather during the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014. Heating degree days were 14% and 9% lower, respectively for the three and six months ended June 30, 2015, compared to the same periods in 2014. Heating degree days for the three and six months ended June 30, 2015 were 10% lower and 1% higher than normal, respectively, compared to 5% 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 second quarter of 2015. Through June 30, 2015, approximately $15 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 for the six months ended June 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., a deal previously announced on October 14, 2014. 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 a wind developer and is expected to be completed in the fourth quarter 2016. At a pre-hearing conference on July 22, 2015 the CPUC established a procedural schedule with an evidentiary hearing to be held at the end of September 2015, and a target date for a CPUC decision on November 6, 2015. Assuming CPUC approval, Colorado Electric will purchase the project for approximately $101 million upon 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 of our five facilities throughout Rapid City. Construction is expected to begin in the third quarter of 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 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.

- 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 six months ended June 30, 2015 compared to the same periods in 2014. The average hedged price received for natural gas decreased by 44% and 39%, respectively for the three and six months ended June 30, 2015 compared to the same periods in 2014. The average hedged price received for oil decreased by 17% and 22%, respectively for the three and six months ended June 30, 2015 compared to the same periods in 2014. Oil and Gas production volumes increased 32% and 28%, respectively, for the three and six months ended June 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. In the first and second quarters of 2015, our Oil and Gas segment recorded non-cash ceiling test impairments of $22 million and $94 million, respectively, as a result of continued low commodity prices. Using our current reserves information, further ceiling test impairments could occur in 2015 if commodity prices for crude oil and natural gas remain at current levels.

- 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 are currently drilling the last of 13 Mancos Shale wells for our 2014/2015 drilling program on three separate pads in the Piceanse Basin. We placed three wells on production in the first quarter of 2015, and production results to date from these wells have been favorable, and exceeded our expectations. We expect to complete three wells in the third quarter of 2015 and three more in the fourth quarter of 2015. In the first quarter of 2015, we increased our planned capital expenditures to $167 million from $123 million, and now expect our total 2015 capital expenditures to be approximately $179 million. The overall change from $123 million to $179 million is due to approximately $50 million of 2014 carryover drilling program carryover and another $35 million for non-consenting working interest owners in the program, offset by approximately $30 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 producing wells, as well as our expectation of continued low commodity prices.

Corporate Activities

- 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 $720 million in debt projected at closing. The effective purchase price is $1.74 billion after taking into account approximately $150 million in tax benefits consisting of acquired NOL’s and goodwill tax benefits, resulting from the transaction. 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 acquisition of SourceGas is expected to close during the first half of 2016. The transaction is subject to customary closing conditions, regulatory approvals from the APSC, CPUC, NPSC and WPSC, and is also subject to notification, clearance and reporting requirements under the Hart-Scott-Rodino Act.

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

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

- On July 13, 2015, Fitch affirmed the BHC credit rating 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, 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 June 30,			Six Months Ended June 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue — electric	$164,023	$154,544	$9,479	$333,940	$322,909	$11,031
Revenue — gas	8,237	7,340	897	24,718	21,077	3,641
Total revenue	172,260	161,884	10,376	358,658	343,986	14,672
Fuel, purchased power and cost of gas — electric	64,185	69,723	(5,538)	131,875	148,142	(16,267)
Purchased gas — gas	3,769	4,051	(282)	13,867	12,325	1,542
Total fuel, purchased power and cost of gas	67,954	73,774	(5,820)	145,742	160,467	(14,725)
Gross margin — electric	99,838	84,821	15,017	202,065	174,767	27,298
Gross margin — gas	4,468	3,289	1,179	10,851	8,752	2,099
Total gross margin	104,306	88,110	16,196	212,916	183,519	29,397
Operations and maintenance	43,824	40,272	3,552	87,808	82,872	4,936
Depreciation and amortization	20,541	19,274	1,267	41,585	38,361	3,224
Total operating expenses	64,365	59,546	4,819	129,393	121,233	8,160
Operating income	39,941	28,564	11,377	83,523	62,286	21,237
Interest expense, net	(13,558)	(11,829)	(1,729)	(27,391)	(23,841)	(3,550)
Other income (expense), net	171	352	(181)	240	608	(368)
Income tax benefit (expense)	(8,852)	(5,660)	(3,192)	(19,741)	(13,051)	(6,690)
Net income (loss)	$17,702	$11,427	$6,275	$36,631	$26,002	$10,629

Revenue - Electric (in thousands)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Residential:				
Black Hills Power	$15,470	$14,332	$35,610	$34,392
Cheyenne Light	8,929	8,167	19,194	17,840
Colorado Electric	22,147	21,316	46,717	45,995
Total Residential	46,546	43,815	101,521	98,227
Commercial:				
Black Hills Power	24,433	21,200	49,174	42,728
Cheyenne Light	15,739	15,238	31,559	29,631
Colorado Electric	23,555	23,101	45,719	44,991
Total Commercial	63,727	59,539	126,452	117,350
Industrial:				
Black Hills Power	8,459	7,534	16,758	14,869
Cheyenne Light	8,538	7,304	17,164	14,528
Colorado Electric	10,400	9,535	21,156	18,573
Total Industrial	27,397	24,373	55,078	47,970
Municipal:				
Black Hills Power	859	846	1,717	1,638
Cheyenne Light	582	514	1,098	968
Colorado Electric	2,956	3,277	6,018	6,584
Total Municipal	4,397	4,637	8,833	9,190
Total Retail Revenue - Electric	142,067	132,364	291,884	272,737
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	3,979	4,473	9,399	10,071
Off-system Wholesale:				
Black Hills Power	6,666	5,411	13,301	14,486
Cheyenne Light	992	1,787	2,953	4,174
Colorado Electric	418	1,912	502	3,995
Total Off-system Wholesale	8,076	9,110	16,756	22,655
Other Revenue:				
Black Hills Power	8,172	6,945	12,362	13,823
Cheyenne Light	566	534	1,041	1,287
Colorado Electric	1,163	1,118	2,498	2,336
Total Other Revenue	9,901	8,597	15,901	17,446
Total Revenue - Electric	$164,023	$154,544	$333,940	$322,909

Quantities Generated and Purchased (in MWh)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Generated —				
Coal-fired:				
Black Hills Power [(a)]	399,763	336,842	776,597	754,090
Cheyenne Light [(b)]	180,082	162,847	374,798	332,636
Total Coal-fired	579,845	499,689	1,151,395	1,086,726
Natural Gas and Oil:				
Black Hills Power	16,883	2,665	19,761	4,972
Cheyenne Light	7,711	—	10,550	—
Colorado Electric [(c)]	34,255	40,599	37,747	58,668
Total Natural Gas and Oil	58,849	43,264	68,058	63,640
Wind:				
Colorado Electric	10,177	13,230	19,268	27,558
Total Wind	10,177	13,230	19,268	27,558
Total Generated:				
Black Hills Power	416,646	339,507	796,358	759,062
Cheyenne Light	187,793	162,847	385,348	332,636
Colorado Electric	44,432	53,829	57,015	86,226
Total Generated	648,871	556,183	1,238,721	1,177,924
Purchased —				
Black Hills Power	350,892	365,463	789,335	796,265
Cheyenne Light	173,151	197,225	360,930	404,543
Colorado Electric	454,859	467,197	927,046	937,299
Total Purchased	978,902	1,029,885	2,077,311	2,138,107
Total Generated and Purchased:				
Black Hills Power	767,538	704,970	1,585,693	1,555,327
Cheyenne Light	360,944	360,072	746,278	737,179
Colorado Electric	499,291	521,026	984,061	1,023,525
Total Generated and Purchased	1,627,773	1,586,068	3,316,032	3,316,031

(a) Increase was due to a planned annual outage at Neil Simpson II and an unplanned outage for a catalyst replacement at Wygen III
during the three and and six months ended June 30, 2014.
(b) Increase was due to purchasing spinning reserve in the current year compared to carrying spinning reserve in the prior year.
(c) Decrease in 2015 generation was primarily driven by commodity prices that impacted power marketing sales.

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	Three Months Ended June 30,		Six Months Ended June 30,	
Quantity (in MWh)	2015	2014	2015	2014
Residential:				
Black Hills Power	110,017	107,394	256,980	278,704
Cheyenne Light	58,169	57,328	125,668	127,983
Colorado Electric	136,767	132,256	293,981	285,887
Total Residential	304,953	296,978	676,629	692,574
Commercial:				
Black Hills Power	189,889	176,541	384,967	360,989
Cheyenne Light	130,456	129,688	261,559	256,100
Colorado Electric	169,508	174,239	334,589	332,418
Total Commercial	489,853	480,468	981,115	949,507
Industrial:				
Black Hills Power	102,494	104,914	214,353	205,765
Cheyenne Light	118,180	94,861	229,276	185,586
Colorado Electric	110,925	111,090	229,032	201,207
Total Industrial	331,599	310,865	672,661	592,558
Municipal:				
Black Hills Power	7,036	7,709	14,736	15,394
Cheyenne Light	2,174	2,131	4,724	4,624
Colorado Electric	28,808	31,385	56,921	58,073
Total Municipal	38,018	41,225	76,381	78,091
Total Retail Quantity Sold	1,164,423	1,129,536	2,406,786	2,312,730
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power [(a)]	64,896	71,999	149,167	167,227
Off-system Wholesale:				
Black Hills Power	246,213	169,498	491,851	424,294
Cheyenne Light	24,662	42,250	73,534	94,606
Colorado Electric [(b)]	13,501	50,178	15,970	80,924
Total Off-system Wholesale	284,376	261,926	581,355	599,824
Total Quantity Sold:				
Black Hills Power	720,545	638,055	1,512,054	1,452,373
Cheyenne Light	333,641	326,258	694,761	668,899
Colorado Electric	459,509	499,148	930,493	958,509
Total Quantity Sold	1,513,695	1,463,461	3,137,308	3,079,781
Other Uses, Losses or Generation, net [(c)]:				
Black Hills Power	46,993	66,915	73,639	102,954
Cheyenne Light	27,303	33,814	51,517	68,280
Colorado Electric	39,782	21,878	53,568	65,016
Total Other Uses, Losses and Generation, net	114,078	122,607	178,724	236,250

Total Energy	1,627,773	1,586,068	3,316,032	3,316,031

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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.

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Degree Days	Three Months Ended June 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	1,005	— %	(2)%	1,025	2 %
Cheyenne Light	1,173	(2)%	(2)%	1,191	— %
Colorado Electric	624	2 %	(1)%	633	4 %
Combined [a] [b]	863	— %	(2)%	877	2 %
Cooling Degree Days:					
Black Hills Power	96	(10)%	(3)%	99	(7)%
Cheyenne Light	62	22 %	24%	50	(2)%
Colorado Electric	245	8 %	17%	209	(8)%
Combined [a] [b]	158	4 %	13%	140	(7)%

Degree Days	Six Months Ended June 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	3,878	(8)%	(13)%	4,435	5 %
Cheyenne Light	3,824	(9)%	(13)%	4,397	4 %
Colorado Electric	3,022	(6)%	(9)%	3,303	3 %
Combined [a] [b]	3,473	(8)%	(11)%	3,905	4 %
Cooling Degree Days:					
Black Hills Power	96	(10)%	(3)%	99	(7)%
Cheyenne Light	62	22 %	24%	50	(2)%
Colorado Electric	245	8 %	17%	209	(9)%
Combined [a] [b]	158	4 %	13%	140	(7)%

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

(b) Heating degree days generally have a larger impact on margin during the second quarter than cooling degree days due to the seasonal difference in peak heating degree days compared to peak cooling degree days.

Electric Utilities Power Plant Availability	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Coal-fired plants [a]	96.4 %	84.8 %	93.8 %	90.1 %
Other plants [b] [c]	93.7 %	89.9 %	94.7 %	84.0 %
Total availability	94.7 %	87.7 %	94.4 %	86.6 %

(a) The three months and six months ended June 30, 2014 reflect a planned annual outage at Neil Simpson II and an unplanned outage for a catalyst replacement at Wygen III.

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

(c) The six months ended June 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 is Cheyenne Light's natural gas distribution systems. The following table summarizes certain operating information for these natural gas distribution operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenue - Natural Gas (in thousands):				
Residential	$4,541	$4,519	$13,253	$12,743
Commercial	2,413	1,975	7,367	5,951
Industrial	534	616	2,434	1,903
Other Sales Revenue	749	230	1,664	480
Total Revenue - Natural Gas	$8,237	$7,340	$24,718	$21,077
Gross Margin (in thousands):				
Residential	$2,745	$2,383	$6,523	$5,987
Commercial	891	631	2,319	1,962
Industrial	83	47	345	323
Other Gross Margin	749	228	1,664	480
Total Gross Margin	$4,468	$3,289	$10,851	$8,752
Volumes Sold (Dth):				
Residential	469,750	450,715	1,410,157	1,485,892
Commercial	398,228	284,493	1,068,817	848,887
Industrial	118,781	120,558	420,058	376,485
Total Volumes Sold	986,759	855,766	2,899,032	2,711,264

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2014: Net income for the Electric Utilities was $18 million for the three months ended June 30, 2015, compared to Net income of $11 million for the three months ended June 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 $10.6 million compared to the same period in the prior year. Electric margins were favorably impacted by higher retail load and demand that increased megawatt hours sold driving an increase of $1.8 million. Gas margins at Cheyenne Light were favorably impacted by our MGTC system acquisition increasing margins by $0.7 million. An increase in wholesale megawatt hours sold resulted in an increase of $1.2 million. Partially offsetting these increases was a negative weather impact on electric residential retail margins of $0.6 million primarily driven by a 2% decrease in heating degree days compared to the same period 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, and an increase in employee costs.

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 is comparable to the prior year.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014: Net income for the Electric Utilities was $37 million for the six months ended June 30, 2015, compared to Net income of $26 million for the six months ended June 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 $18.6 million compared to the same period in the prior year. Electric margins were favorably impacted by higher retail load and demand that increased megawatt hours sold driving an increase of $6.1 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 system acquisition increasing margins by $1.1 million. An increase in wholesale megawatt hours sold driven by outages in the prior year resulted in an increase of $0.9 million. Partially offsetting these increases was a negative weather impact on electric and gas residential retail margins of $3.7 million driven by a 11% decrease in heating degree days compared to the same period 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.

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 June 30,			Six Months Ended June 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$72,079	$95,350	$(23,271)	$301,227	$346,582	$(45,355)
Other — non-regulated services	7,347	7,149	198	15,850	15,254	596
Total revenue	79,426	102,499	(23,073)	317,077	361,836	(44,759)
Cost of sales						
Natural gas — regulated	29,730	52,266	(22,536)	182,015	223,040	(41,025)
Other — non-regulated services	3,571	3,675	(104)	7,484	7,397	87
Total cost of sales	33,301	55,941	(22,640)	189,499	230,437	(40,938)
Gross margin	46,125	46,558	(433)	127,578	131,399	(3,821)
Operations and maintenance	30,876	33,454	(2,578)	66,308	68,832	(2,524)
Depreciation and amortization	7,356	6,538	818	14,402	13,059	1,343
Total operating expenses	38,232	39,992	(1,760)	80,710	81,891	(1,181)
Operating income (loss)	7,893	6,566	1,327	46,868	49,508	(2,640)
Interest expense, net	(3,581)	(3,722)	141	(7,390)	(7,574)	184
Other income (expense), net	19	19	—	8	1	7
Income tax benefit (expense)	(1,166)	(869)	(297)	(14,109)	(15,243)	1,134
Net income (loss)	$3,165	$1,994	$1,171	$25,377	$26,692	$(1,315)

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	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue (in thousands)	2015	2014	2015	2014
Residential:				
Colorado	$9,861	$9,435	$35,597	$33,122
Nebraska	15,628	17,519	72,072	80,411
Iowa	12,978	22,052	59,344	76,816
Kansas	8,814	10,348	38,142	43,625
Total Residential	47,281	59,354	205,155	233,974
Commercial:				
Colorado	1,827	2,060	6,924	6,757
Nebraska	3,895	4,590	22,107	24,656
Iowa	4,894	11,202	26,523	37,116
Kansas	2,992	3,624	14,058	15,295
Total Commercial	13,608	21,476	69,612	83,824
Industrial:				
Colorado	218	504	247	581
Nebraska	582	99	899	307
Iowa	443	1,141	1,698	2,313
Kansas	2,756	5,632	4,497	6,718
Total Industrial	3,999	7,376	7,341	9,919
Transportation:				
Colorado	238	217	603	542
Nebraska	2,431	2,542	7,827	8,272
Iowa	1,037	983	2,699	2,744
Kansas	1,430	1,563	3,931	4,056
Total Transportation	5,136	5,305	15,060	15,614
Other Sales Revenue:				
Colorado	373	36	416	67
Nebraska	613	651	1,270	1,354
Iowa	208	262	347	414
Kansas	861	890	2,026	1,416
Total Other Sales Revenue	2,055	1,839	4,059	3,251
Total Regulated Revenue	72,079	95,350	301,227	346,582
Non-regulated Services	7,347	7,149	15,850	15,254
Total Revenue	$79,426	$102,499	$317,077	$361,836

Gross Margin (in thousands)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Residential:				
Colorado	$3,689	$3,597	$10,026	$9,969
Nebraska	9,716	9,925	28,706	30,814
Iowa	8,814	8,993	22,712	24,203
Kansas	6,204	6,529	17,682	18,113
Total Residential	28,423	29,044	79,126	83,099
Commercial:				
Colorado	574	607	1,614	1,667
Nebraska	1,714	1,772	6,383	6,935
Iowa	2,117	2,300	6,753	7,525
Kansas	1,493	1,495	4,880	4,678
Total Commercial	5,898	6,174	19,630	20,805
Industrial:				
Colorado	69	130	90	160
Nebraska	158	33	239	101
Iowa	50	61	131	146
Kansas	557	696	950	932
Total Industrial	834	920	1,410	1,339
Transportation:				
Colorado	238	216	603	542
Nebraska	2,431	2,541	7,827	8,272
Iowa	1,037	982	2,699	2,743
Kansas	1,430	1,563	3,931	4,056
Total Transportation	5,136	5,302	15,060	15,613
Other Sales Margins:				
Colorado	374	37	417	68
Nebraska	613	653	1,270	1,356
Iowa	208	263	347	414
Kansas	863	692	1,952	849
Total Other Sales Margins	2,058	1,645	3,986	2,687
Total Regulated Gross Margin	42,349	43,085	119,212	123,543
Non-regulated Services	3,776	3,473	8,366	7,856
Total Gross Margin	$46,125	$46,558	$127,578	$131,399

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Residential:				
Colorado	1,049,937	1,018,966	3,996,742	4,040,400
Nebraska	1,147,696	1,278,283	7,106,652	8,264,576
Iowa	1,045,198	1,249,921	6,561,235	7,892,965
Kansas	596,296	715,890	3,950,110	4,597,445
Total Residential	3,839,127	4,263,060	21,614,739	24,795,386
Commercial:				
Colorado	218,528	255,312	835,726	891,002
Nebraska	442,952	485,023	2,623,646	2,960,179
Iowa	685,373	884,997	3,565,464	4,370,689
Kansas	334,343	391,548	1,769,847	1,933,515
Total Commercial	1,681,196	2,016,880	8,794,683	10,155,385
Industrial:				
Colorado	43,535	101,468	45,937	111,793
Nebraska	107,625	12,168	153,325	39,133
Iowa	87,777	119,710	278,782	313,573
Kansas (a)	701,122	1,084,608	1,025,901	1,264,695
Total Industrial	940,059	1,317,954	1,503,945	1,729,194
Wholesale and Other:				
Kansas (b)	927	32,274	14,902	100,907
Total Wholesale and Other	927	32,274	14,902	100,907
Total Distribution Quantities Sold	6,461,309	7,630,168	31,928,269	36,780,872
Transportation:				
Colorado	230,437	209,799	610,486	540,143
Nebraska	6,509,208	6,623,555	15,558,983	16,586,774
Iowa	4,599,639	4,319,339	10,687,688	10,476,705
Kansas	3,564,124	3,594,159	7,861,476	8,421,296
Total Transportation	14,903,408	14,746,852	34,718,633	36,024,918
Total Distribution Quantities Sold and Transportation	21,364,717	22,377,020	66,646,902	72,805,790

(a) Decrease from prior year was driven by decreased irrigation load due to increased rainfall across the service territory compared to the prior year.
(b) Decrease 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 June 30,				
	2015			2014	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Colorado	887	(4)%	(4)%	924	—%
Nebraska	474	(17)%	(18)%	580	1%
Iowa	649	(6)%	(16)%	775	11%
Kansas (a)	403	(10)%	(16)%	480	7%
Combined (b)	611	(10)%	(14)%	711	5%

	Six Months Ended June 30,				
	2015			2014	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Colorado	3,422	(8)%	(10)%	3,783	2%
Nebraska	3,488	(3)%	(9)%	3,852	6%
Iowa	4,483	10%	(9)%	4,949	18%
Kansas (a)	2,725	(6)%	(14)%	3,169	8%
Combined (b)	3,833	1%	(9)%	4,235	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 June 30, 2015 Compared to the Three Months Ended June 30, 2014: Net income for the Gas Utilities was $3.2 million for the three months ended June 30, 2015, compared to Net income of $2.0 million for the three months ended June 30, 2014, as a result of:

Gross margin decreased primarily due to a $0.7 million impact from milder weather than in the same period in the prior year. Heating degree days were 14% lower for the three months ended June 30, 2015, compared to the same period in the prior year and 10% lower than normal in the current year, compared to 5% higher than normal in the prior year. Partially offsetting this weather impact was a $0.3 million increase from year over year customer growth.

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 was comparable to the same period in the prior year.

Income tax benefit (expense): The effective tax rate decreased as a result of a favorable state tax true-up adjustment.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014: Net income for the Gas Utilities was $25 million for the six months ended June 30, 2015, compared to Net income of $27 million for the six months ended June 30, 2014, as a result of:

Gross margin decreased primarily due to a $6.0 million impact from milder weather than in the same period in the prior year. Heating degree days were 9% lower for the six months ended June 30, 2015, compared to the same period in the prior year and 1% higher than normal in the current year, compared to 12% higher than normal in the prior year. Partially offsetting this weather impact was a $1.3 million increase from base rate adjustments and riders at Kansas Gas which were effective January 1, 2015, and a $0.9 million increase from year-over-year customer growth.

Operations and maintenance decreased primarily due to 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 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.

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) On December 16, 2014, Kansas Gas received approval from the KCC to increase base rates by $5.2 million, effective January 2015. The approval was a Global Settlement and did not stipulate return on equity and capital structure. This increase in base rates allows Kansas Gas to recover a return on investments in infrastructure and recovery of increased operating costs.

(c)

On December 19, 2014, Colorado Electric received approval from the CPUC for an annual electric revenue increase of $3.1 million. The approval allows a 9.83% return on equity and a capital structure of 49.83% equity and 50.17% debt, as well as the implementation of a construction financing rider. This approval allows Colorado Electric to recover increased operating expenses and a return on infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The implementation of the construction financing rider 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.

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 June 30,			Six Months Ended June 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue	$22,309	$21,980	$329	$44,983	$44,328	$655
Operations and maintenance	8,483	8,733	(250)	16,311	16,410	(99)
Depreciation and amortization	1,115	1,154	(39)	2,249	2,363	(114)
Total operating expense	9,598	9,887	(289)	18,560	18,773	(213)
Operating income	12,711	12,093	618	26,423	25,555	868
Interest expense, net	(788)	(934)	146	(1,674)	(1,862)	188
Other (expense) income, net	7	2	5	5	(7)	12
Income tax (expense) benefit	(4,381)	(3,967)	(414)	(9,060)	(8,419)	(641)
Net income (loss)	$7,549	$7,194	$355	$15,694	$15,267	$427

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Quantities Sold, Generated and Purchased (MWh) (a)				
Sold				
Black Hills Colorado IPP	267,360	273,200	551,851	559,156
Black Hills Wyoming (b)	165,557	138,377	325,115	278,985
Total Sold	432,917	411,577	876,966	838,141
Generated				
Black Hills Colorado IPP	267,360	273,200	551,851	559,156
Black Hills Wyoming	139,267	141,458	277,240	282,136
Total Generated	406,627	414,658	829,091	841,292
Purchased				
Black Hills Wyoming (b)	13,099	16	37,491	1,005
Total Purchased	13,099	16	37,491	1,005

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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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Contracted power plant fleet availability:				
Coal-fired plant	97.4 %	98.7 %	97.8 %	99.0 %
Natural gas-fired plants	99.0 %	99.2 %	99.0 %	98.5 %
Total availability	98.6 %	99.1 %	98.7 %	98.6 %

Results of Operations for Power Generation for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2014: Net income for the Power Generation segment was $7.5 million for the three months ended June 30, 2015, compared to Net income of $7.2 million for the same period in 2014 as a result of:

Revenue was comparable to the prior year reflecting an increase in PPA pricing and an increase in fired-hours and megawatt hours sold, 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 was higher in 2015 primarily due to an unfavorable state tax true-up adjustment .

Results of Operations for Power Generation for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014: Net income for the Power Generation segment was $16 million for the six months ended June 30, 2015, compared to Net income of $15 million for the same period in 2014 as a result of:

Revenue was comparable to the prior year reflecting an increase in PPA pricing, 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 was higher in 2015 primarily due to the increase in liability with respect to uncertain tax positions related to research and development credits.

Coal Mining

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue	$16,725	$14,651	$2,074	$32,659	$30,149	$2,510
Operations and maintenance	10,661	10,023	638	20,565	20,154	411
Depreciation, depletion and amortization	2,461	2,570	(109)	4,964	5,260	(296)
Total operating expenses	13,122	12,593	529	25,529	25,414	115
Operating income (loss)	3,603	2,058	1,545	7,130	4,735	2,395
Interest (expense) income, net	(102)	(113)	11	(191)	(216)	25
Other income, net	548	589	(41)	1,133	1,192	(59)
Income tax benefit (expense)	(1,000)	(518)	(482)	(2,013)	(1,231)	(782)
Net income (loss)	$3,049	$2,016	$1,033	$6,059	$4,480	$1,579

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Tons of coal sold	1,076	1,063	2,095	2,150
Cubic yards of overburden moved	1,392	1,010	2,805	1,920
Revenue per ton	$15.54	$13.79	$15.59	$14.03

Results of Operations for Coal Mining for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2014: Net income for the Coal Mining segment was $3.0 million for the three months ended June 30, 2015, compared to Net income of $2.0 million for the same period in 2014 as a result of:

Revenue increased primarily due to a 13% increase in price per ton sold, and a 1% increase 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 in 2015 was higher due primarily to the reduced impact of the tax benefit of percentage depletion.

Results of Operations for Coal Mining for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014: Net income for the Coal Mining segment was $6.1 million for the six months ended June 30, 2015, compared to Net income of $4.5 million for the same period in 2014 as a result of:

Revenue increased primarily due to a 11% 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 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 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 higher production taxes and royalties driven by increased revenue, partially offset by to mining efficiencies resulting in reduced major maintenance, and 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 was higher due primarily to the reduced impact of the tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	Variance	2015	2014	Variance
	(in thousands)					
Revenue	$12,319	$15,148	$(2,829)	$23,586	$29,998	$(6,412)
Operations and maintenance	10,988	10,239	749	21,905	21,378	527
Depreciation, depletion and amortization	8,790	6,456	2,334	16,301	12,254	4,047
Impairment of long-lived assets	94,484	—	94,484	116,520	—	116,520
Total operating expenses	114,262	16,695	97,567	154,726	33,632	121,094
Operating income (loss)	(101,943)	(1,547)	(100,396)	(131,140)	(3,634)	(127,506)
Interest income (expense), net	(478)	(442)	(36)	(862)	(897)	35
Other income (expense), net	7	49	(42)	(216)	87	(303)
Impairment of equity investments	(5,170)	—	(5,170)	(5,170)	—	(5,170)
Income tax benefit (expense)	36,389	807	35,582	47,078	1,816	45,262
Net income (loss) [(a)]	$(71,195)	$(1,133)	$(70,062)	$(90,310)	$(2,628)	$(87,682)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Production:				
Bbls of oil sold	98,905	92,228	179,635	166,490
Mcf of natural gas sold	2,701,721	1,840,826	4,955,763	3,600,790
Bbls of NGL sold	33,271	42,003	62,041	69,044
Mcf equivalent sales	3,494,780	2,646,210	6,405,823	5,013,992

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Average price received: [(a)] [(b)]				
Oil/Bbl	$65.09	$78.18	$65.88	$84.56
Gas/Mcf	$1.79	$3.17	$1.98	$3.25
NGL/Bbl	$19.82	$33.76	$17.00	$39.74
Depletion expense/Mcfe	$2.22	$2.01	$2.21	$1.95

(a) Net of hedge settlement gains and losses.

(b) Ceiling test impairments of $94 and $117 million were recorded for the three and six months ended June 30, 2015. If crude oil and natural gas prices remain at or near the current levels, additional ceiling impairment charges could occur in 2015.

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

	Three Months Ended June 30, 2015				Three Months Ended June 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	$1.25	$1.38	$0.57	$3.20	$1.39	$1.22	$0.59	$3.20
Piceance	0.62	1.76	0.17	2.55	0.26	4.02	0.35	4.63
Powder River	2.09	—	0.83	2.92	1.55	—	1.15	2.70
Williston	1.13	—	0.36	1.49	1.31	—	1.41	2.72
All other properties	2.10	—	1.08	3.18	1.30	—	0.77	2.07
Total weighted average	$1.12	$1.18	$0.44	$2.74	$1.08	$1.58	$0.72	$3.38

	Six Months Ended June 30, 2015				Six Months Ended June 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	$1.42	$1.34	$0.47	$3.23	$1.46	$1.21	$0.61	$3.28
Piceance	0.51	2.05	0.18	2.74	0.11	2.76	0.45	3.32
Powder River	2.47	—	0.70	3.17	1.90	—	1.23	3.13
Williston	0.74	—	0.24	0.98	1.08	—	1.59	2.67
All other properties	1.64	—	0.68	2.32	1.47	—	0.36	1.83
Total weighted average	$1.15	$1.25	$0.38	$2.78	$1.13	$1.22	$0.73	$3.08

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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, and 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 June 30, 2015 Compared to the Three Months Ended June 30, 2014: Net loss for the Oil and Gas segment was $71 million for the three months ended June 30, 2015, compared to Net loss of $1.1 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 17% decrease in the average hedged price received for crude oil sold, and a 44% decrease in the average hedged price received for natural gas sold. A production increase of 32%, driven primarily by three new Piceance Mancos Shale wells placed on production in the first quarter 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, partially offset by lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization increased primarily due to a higher 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 $3.39 per Mcf, adjusted to $2.14 per Mcf at the wellhead, for natural gas, and $71.68 per barrel, adjusted to $63.76 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 in 2015 was lower due to a reduced favorable impact of the tax effect of the percentage depletion deduction compared to the same period in the prior year.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014: Net loss for the Oil and Gas segment was $90 million for the six months ended June 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 22% decrease in the average hedged price received for crude oil sold, and a 39% decrease in the average hedged price received for natural gas sold. A production increase of 28%, driven primarily by three new Piceance Mancos Shale wells placed on production in the first quarter 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, partially offset by lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate applied to greater production.

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 $3.39 per Mcf, adjusted to $2.14 per Mcf at the wellhead, for natural gas, and $71.68 per barrel, adjusted to $63.76

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 in 2015 was lower due to a reduced favorable impact of the tax effect of the percentage depletion deduction compared to the same period in the prior year.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2014: Net loss for Corporate was $2.1 million for the three months ended June 30, 2015, compared to Net loss of $1.2 million for the three months ended June 30, 2014. The variance from the prior year was primarily due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition occurring during the three months ended June 30, 2015, compared to the three months ended June 30, 2014.

Results of Operations for Corporate activities for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014: Net loss for Corporate was $1.4 million for the six months ended June 30, 2015, compared to Net loss of $0.8 million for the six months ended June 30, 2014. The variance from the prior year was primarily due to higher corporate expenses, primarily driven by costs related to the SourceGas acquisition occurring during the six months ended June 30, 2015 compared to the six months ended June 30, 2014.

Critical Accounting Policies

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

Cash Flow Activities

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

Cash provided by (used in):	2015	2014	Increase (Decrease)
Operating activities	$254,408	$173,835	$80,573
Investing activities	$(207,124)	$(180,296)	$(26,828)
Financing activities	$18,708	$13,317	$5,391

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

Operating Activities

Net cash provided by operating activities was $254 million for the six months ended June 30, 2015, compared to net cash provided by operating activities of $174 million for the same period in 2014 for a variance of $81 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $8.1 million higher for the six months ended June 30, 2015 to the same period in the prior year.

- Net inflows from operating assets and liabilities were $52 million for the six months ended June 30, 2015, compared to net cash outflows of $24 million in the same period in the prior year. This $76 million variance was primarily due to:

- Cash inflows increased for the six months ended June 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 to lower natural gas prices;

- Cash inflows increased as a result of lower customer receivables and lower working capital requirements for natural gas for the six months ended June 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; and

- Cash outflows increased due to decreased accrued expenditures primarily at our Oil and Gas segment related to drilling activity for the six months ended June 30, 2015 compared to the same period in the prior year.

Investing Activities

Net cash used in investing activities was $207 million for the six months ended June 30, 2015, compared to net cash used in investing activities of $180 million for the same period in 2014. The variance was primarily driven by:

- Capital expenditures of approximately $206 million for the six months ended June 30, 2015, compared to $177 million for the six months ended June 30, 2014. The increase is related primarily to higher capital expenditures at our Oil and Gas segment driven by drilling activity. In the prior year the Oil and Gas segment capital expenditures were affected by weather delays. Capital expenditures also increased at our Coal Mine, and Gas Utilities for the six months ended June 30, 2015 compared to the prior year. Offsetting these capital expenditure increases is the construction of Cheyenne Prairie at our Electric Utilities segment occurring in the prior year.

Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2015 was $19 million, compared to $13 million 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.

- Net Short-term borrowings under the revolving credit facility for the six months ended June 30, 2015 were $19 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 $36 million for the six months ended June 30, 2015, or $0.81 per share. On July 28, 2015, our board of directors declared a quarterly dividend of $0.405 per share payable September 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 June 30, 2015	Letters of Credit at June 30, 2015	Available Capacity at June 30, 2015
Revolving Credit Facility	June 26, 2020	$500	$106	$23	$371

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 June 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 1.5 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 $4.7 million at June 30, 2015.

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 6th, 2015, we entered into a Bridge Term Loan Agreement with Credit Suisse as the Administrate 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 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 .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 Loan Credit 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:

- Evaluate the conversion of our $300 million variable-rate Corporate term loan to fixed rate debt.
- Execute permanent financing options for the acquisition of SourceGas that include:

* $575 million to $675 million in Equity and equity-linked securities,

* $450 million to $550 million in new debt.

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 June 30, 2015, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $325 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 June 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:

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

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 revised and 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:

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 $720 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 consisting of acquired NOLs and goodwill tax benefits, 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 the aformentioned $720 million of assumed debt, $450 million to $550 million of new debt, $575 million to $675 million of equity and equity-linked securities, and the remainder with cash on hand and revolver draws.

Capital Expenditures

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

	Expenditures for the Six Months Ended June 30, 2015 [(a)]	Total 2015 Planned Expenditures [(b)]	Total 2016 Planned Expenditures [(d)]	Total 2017 Planned Expenditures [(d)]
Utilities:				
Electric Utilities	$58,199	$229,300	$225,400	$135,600
Gas Utilities	31,365	69,200	60,100	71,800
Cost of Service Gas	—	—	50,000	100,000
Non-regulated Energy:				
Power Generation	1,534	8,000	2,000	2,600
Coal Mining	4,952	7,000	6,000	6,600
Oil and Gas [(c)]	87,034	179,200	12,300	15,000
Corporate	7,472	6,100	1,500	3,600
	$190,556	$498,800	$357,300	$335,200

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

(b) Includes actual expenditures for the six months ended June 30, 2015.

(c) 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're 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 we expect to complete three wells in the third quarter of 2015 and three more in the fourth quarter of 2015. Completion of the four remaining wells will be deferred based on the positive results of our producing wells, as well as our expectation of continued low commodity prices.

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

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 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 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/A, 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:

	June 30, 2015	December 31, 2014	June 30, 2014
Net derivative (liabilities) assets	$(16,181)	$(16,914)	$(1,647)
Cash collateral offset in Derivatives	16,181	16,914	3,384
Cash Collateral included in Other current assets	5,059	3,093	2,767
Net asset (liability) position	$5,059	$3,093	$4,504

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 June 30, 2015, were as follows:

Natural Gas

	March 31	June 30	September 30	December 31	Total Year
2015					
Swaps - MMBtu	—	—	955,000	1,000,000	1,955,000
Weighted Average Price per MMBtu	$—	$—	$4.00	$4.04	$4.02
2016					
Swaps - MMBtu	585,000	557,500	545,000	545,000	2,232,500
Weighted Average Price per MMBtu	$3.89	$3.87	$3.91	$3.90	$3.89

Crude Oil

	March 31	June 30	September 30	December 31	Total Year
2015					
Swaps - Bbls	—	—	66,000	60,000	126,000
Weighted Average Price per Bbl	$—	$—	$75.95	$84.55	$80.05
2016					
Swaps - Bbls	39,000	39,000	36,000	36,000	150,000
Weighted Average Price per Bbl	$84.55	$84.55	$84.55	$80.93	$83.68

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

	June 30, 2015	December 31, 2014	June 30, 2014
Net derivative (liabilities) assets	$8,940	$14,684	$(5,451)
Cash collateral offset in Derivatives	(8,940)	(14,684)	5,451
Cash Collateral included in Other current assets	2,119	4,392	3,878
Net asset (liability) position	$2,119	$4,392	$3,878

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 9 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:

	June 30, 2015 Designated Interest Rate Swaps [(a)]	December 31, 2014 Designated Interest Rate Swaps [(a)]	June 30, 2014 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	1.50	2.00	2.50
Derivative liabilities, current	$3,289	$3,340	$3,480
Derivative liabilities, non-current	$1,433	$2,680	$4,251
Pre-tax accumulated other comprehensive income (loss)	$(4,722)	$(6,020)	$(7,731)

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(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 June 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.

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 June 30, 2015. Based on their evaluation, they have concluded that our disclosure controls and procedures were not effective at June 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 June 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 above related to the full cost ceiling test impairment calculation.
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 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 are being taken.

- Employees involved with preparation and review of the ceiling test calculation will be 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 will be further updated and refined to ensure the appropriate application of accounting for all components is embedded within the model.
- Management will engage an external consultant with experience in the Oil and Gas industry to assist in reviewing the ceiling test model, when appropriate in consideration of risk associated with market or business changes.

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 15 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 15 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

We may be unable to obtain the approvals required to complete the acquisition of SourceGas or such approvals may contain material restrictions or conditions.

Completion of the SourceGas acquisition is subject to numerous conditions, including approval from various state utility regulatory agencies, and the expiration or termination of the waiting period under the Hart-Scott-Rodino Act. We cannot provide assurance that we will obtain all required consents or approvals, or that the regulatory consents or approvals will not impose conditions on the completion, or require changes to the terms of the acquisition, including restrictions on the business, operations, or financial performance of the utilities we would acquire from SourceGas. These conditions or changes could also delay or materially and adversely affect the business results and our financial condition.

If we do not complete the acquisition, we will still incur and remain liable for significant transaction costs, including legal, accounting, financial advisory and other related costs.

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

Uncertainty about the effect of the acquisition 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 acquisition 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.

If completed, the acquisition may not achieve its intended results.

We entered into the agreement with the expectation that the acquisition would result in various benefits. If the acquisition is completed, achieving the anticipated benefits will be subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

Our credit ratings could be negatively impacted in the future. If this were to occur, it could impact our access to capital, our cost of capital and our other operating costs, which could adversely affect our ability to obtain permanent financing on favorable terms.

After review of the acquisition announcement, our issuer credit ratings were updated on July 13, 2015 by 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 acquisition or for any other reason, including the failure to consummate the acquisition of the utility assets. Any reduction in our credit ratings could adversely affect our ability to complete the SourceGas transaction, to refinance or repay our existing debt, and to complete new financings, including permanent financing of the SourceGas 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 SourceGas acquisition on favorable terms.

We expect to put in place permanent financing of the SourceGas acquisition approximately $720 million of assumed debt, $450 million to $550 million of new debt and $575 million to $675 million of equity and equity-linked securities. Unexpected periods of volatility and disruption in U.S. credit markets could affect our ability to obtain permanent financing for SourceGas 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.

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

There were no unregistered securities sold during the six months ended June 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*	Commitment Letter by and among Black Hills Corporation and Credit Suisse Securities (USA) LLC and Credit Suisse AG dated as of July 12, 2015 (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 14, 2015).
Exhibit 10.2*	First Amendment 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 to the Registrant's Form 8-K file on June 29, 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.

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*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: August 7, 2015

INDEX TO EXHIBITS

[REQUEST REVIEW/UPDATES FROM ROXANN]

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