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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 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 April 30, 2015
Common stock, $1.00 par value	44,821,847 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)
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
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.
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
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CVA	Credit Valuation Adjustment
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
Energy West	Energy West Wyoming, Inc., a subsidiary of Gas Natural, Inc.
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.
IFRS	International Financial Reporting Standards

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.
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)
NPSC	Nebraska Public Service Commission
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 2019.
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended March 31, 2015	2014
	(in thousands, except per share amounts)	
Revenue	$ 441,987	$ 460,169
Operating expenses:		
Utilities -		
Fuel, purchased power and cost of natural gas sold	205,327	230,468
Operations and maintenance	71,084	71,227
Non-regulated energy operations and maintenance	22,050	22,332
Depreciation, depletion and amortization	39,586	36,083
Taxes - property, production and severance	11,936	10,336
Other operating expenses	52	125
Total operating expenses	350,035	370,571
Operating income	91,952	89,598
Other income (expense):		
Interest charges -		
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(19,910)	(17,860)
Allowance for funds used during construction - borrowed	158	270
Capitalized interest	276	257
Interest income	448	390
Allowance for funds used during construction - equity	56	238
Other income (expense), net	331	592
Total other income (expense), net	(18,641)	(16,113)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	73,311	73,485
Equity in earnings (loss) of unconsolidated subsidiaries	(297)	(1)
Income tax benefit (expense)	(25,120)	(25,366)
Net income (loss) available for common stock	$ 47,894	$ 48,118
Earnings (loss) per share of common stock:		
Earnings (loss) per share, Basic	$ 1.08	$ 1.09
Earnings (loss) per share, Diluted	$ 1.07	$ 1.08
Weighted average common shares outstanding:		
Basic	44,541	44,330
Diluted	44,660	44,554
Dividends declared per share of common stock	$ 0.405	$ 0.390

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

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

(unaudited)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(in thousands)	
Net income (loss) available for common stock	$ 47,894	$ 48,118
Other comprehensive income (loss), net of tax:		
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $(1,042) and $1,307 for the three months ended 2015 and 2014, respectively)	1,836	(2,257)
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $1,254 and $(425) for the three months ended 2015 and 2014, respectively)	(1,241)	780
Benefit plan liability adjustments - net gain (loss) (net of tax (expense) benefit of $15 and $2 for the three months ended 2015 and 2014, respectively)	(27)	(2)
Benefit plan liability adjustments - prior service cost (net of tax (expense) benefit of $(90) for the three months ended 2014	—	164
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $19 and $4 for the three months ended 2015 and 2014, respectively)	(36)	(9)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(247) and $(85) for the three months ended 2015 and 2014, respectively)	458	157
Other comprehensive income (loss), net of tax	990	(1,167)
Comprehensive income (loss) available for common stock	$ 48,884	$ 46,951

See Note 11 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of		
	March 31, 2015	December 31, 2014	March 31, 2014
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 63,385	$ 21,218	$ 17,641
Restricted cash and equivalents	2,191	2,056	2
Accounts receivable, net	178,421	189,992	203,625
Materials, supplies and fuel	66,626	91,191	66,187
Derivative assets, current	—	—	1,846
Income tax receivable, net	159	2,053	1,826
Deferred income tax assets, net, current	23,913	48,288	25,780
Regulatory assets, current	56,542	74,396	62,946
Other current assets	47,448	24,842	24,563
Total current assets	438,685	454,036	404,416
Investments	17,210	17,294	16,916
Property, plant and equipment	4,652,058	4,563,400	4,318,194
Less: accumulated depreciation and depletion	(1,351,857)	(1,324,025)	(1,298,398)
Total property, plant and equipment, net	3,300,201	3,239,375	3,019,796
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,121	3,176	3,342
Regulatory assets, non-current	178,935	183,443	138,173
Other assets, non-current	28,280	29,086	28,925
Total other assets, non-current	563,732	569,101	523,836
TOTAL ASSETS	$ 4,319,828	$ 4,279,806	$ 3,964,964

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)

(unaudited)	As of		
	March 31, 2015	December 31, 2014	March 31, 2014
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 88,770	$ 124,139	$ 149,681
Accrued liabilities	166,781	170,115	145,973
Derivative liabilities, current	3,342	3,340	3,498
Regulatory liabilities, current	17,621	3,687	583
Notes payable	102,600	75,000	100,000
Current maturities of long-term debt	—	275,000	—
Total current liabilities	379,114	651,281	399,735
Long-term debt, net of current maturities	1,542,658	1,267,589	1,396,949
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	522,290	523,716	466,856
Derivative liabilities, non-current	2,143	2,680	4,805
Regulatory liabilities, non-current	148,918	145,144	116,793
Benefit plan liabilities	162,334	158,966	113,324
Other deferred credits and other liabilities	154,604	154,406	129,083
Total deferred credits and other liabilities	990,289	984,912	830,861
Commitments and contingencies (See Notes 7, 8, 13, 14)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,856,790; 44,714,072; and 44,666,953 shares, respectively	44,857	44,714	44,667
Additional paid-in capital	749,517	748,840	742,016
Retained earnings	629,135	599,389	570,963
Treasury stock, at cost – 33,755; 42,226; and 37,038 shares, respectively	(1,688)	(1,875)	(1,638)
Accumulated other comprehensive income (loss)	(14,054)	(15,044)	(18,589)
Total stockholders' equity	1,407,767	1,376,024	1,337,419
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,319,828	$ 4,279,806	$ 3,964,964

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Three Months Ended March 31,	
	2015	2014
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$ 47,894	$ 48,118
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	39,586	36,083
Deferred financing cost amortization	519	568
Stock compensation	2,083	3,716
Deferred income taxes	22,048	25,953
Employee benefit plans	5,283	3,703
Other adjustments, net	6,748	5,190
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	25,689	22,291
Accounts receivable, unbilled revenues and other operating assets	47,947	(78,576)
Accounts payable and other operating liabilities	(44,652)	29,074
Other operating activities, net	(1,658)	1,978
Net cash provided by (used in) operating activities	151,487	98,098
Investing activities:		
Property, plant and equipment additions	(117,523)	(83,609)
Other investing activities	(348)	(3,220)
Net cash provided by (used in) investing activities	(117,871)	(86,829)
Financing activities:		
Dividends paid on common stock	(18,148)	(17,399)
Common stock issued	999	881
Short-term borrowings - issuances	77,700	86,800
Short-term borrowings - repayments	(50,100)	(69,300)
Other financing activities	(1,900)	(2,451)
Net cash provided by (used in) financing activities	8,551	(1,469)
Net change in cash and cash equivalents	42,167	9,800
Cash and cash equivalents, beginning of period	21,218	7,841
Cash and cash equivalents, end of period	$ 63,385	$ 17,641

See Note 12 for supplemental disclosure of cash flow information.

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

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

(1) MANAGEMENT’S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the “Company,” “us,” “we,” or “our”), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2014 Annual Report on Form 10-K 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 March 31, 2015, December 31, 2014, and March 31, 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 months ended March 31, 2015 and March 31, 2014, and our financial condition as of March 31, 2015, December 31, 2014, and March 31, 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.

<u>Simplifying the Presentation of Debt Issuance Costs, ASU 2015-03</u>

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 April 1, 2015, FASB voted to propose to defer the effective date of ASU 2014-09 by one year. The proposed guidance would be effective for annual and interim reporting periods beginning after December 15, 2017 and early adoption is permitted. We are currently assessing the impact, if any, that ASU 2014-09 will have on our financial position, results of operations or cash flows.

(2) BUSINESS SEGMENT INFORMATION

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

Three Months Ended March 31, 2015	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$ 182,974	$ 3,424	$ 18,929
Gas	237,651	—	22,212
Non-regulated Energy:			
Power Generation	1,953	20,721	8,145
Coal Mining	8,142	7,792	3,010
Oil and Gas	11,267	—	(5,071)
Corporate activities	—	—	669
Inter-company eliminations	—	(31,937)	—
Total	$ 441,987	$ —	$ 47,894

Three Months Ended March 31, 2014	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$ 178,095	$ 4,007	$ 14,575
Gas	259,337	—	24,698
Non-regulated Energy:			
Power Generation	1,269	21,079	8,073
Coal Mining	6,618	8,880	2,464
Oil and Gas	14,850	—	(2,022)
Corporate activities	—	—	330
Inter-company eliminations	—	(33,966)	—
Total	$ 460,169	$ —	$ 48,118

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

Total Assets (net of inter-company eliminations) as of:	March 31, 2015	December 31, 2014	March 31, 2014
Utilities:			
Electric [(a)]	$ 2,817,423	$ 2,748,680	$ 2,572,616
Gas	839,802	906,922	842,660
Non-regulated Energy:			
Power Generation [(a)]	75,945	76,945	90,643
Coal Mining	77,399	74,407	74,523
Oil and Gas	403,657	366,247	295,083
Corporate activities	105,602	106,605	89,439
Total assets	$ 4,319,828	$ 4,279,806	$ 3,964,964

(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.

(3) ACCOUNTS RECEIVABLE

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

March 31, 2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 53,862	$ 24,540	$ (834)	$ 77,568
Gas Utilities	63,252	28,785	(1,588)	90,449
Power Generation	1,152	—	—	1,152
Coal Mining	3,638	—	—	3,638
Oil and Gas	4,646	—	(13)	4,633
Corporate	981	—	—	981
Total	$ 127,531	$ 53,325	$ (2,435)	$ 178,421

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

March 31, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 53,733	$ 20,063	$ (690)	$ 73,106
Gas Utilities	77,982	35,791	(814)	112,959
Power Generation	1,340	—	—	1,340
Coal Mining	2,616	—	—	2,616
Oil and Gas	10,920	—	(13)	10,907
Corporate	2,697	—	—	2,697
Total	$ 149,288	$ 55,854	$ (1,517)	$ 203,625

(4) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of March 31, 2015	As of December 31, 2014	As of March 31, 2014
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a) (d)]	1	$ 30,833	$ 23,820	$ 23,935
Deferred gas cost adjustments [(a)(d)]	2	6,138	37,471	38,505
Gas price derivatives [(a)]	7	21,606	18,740	4,420
AFUDC [(b)]	45	12,114	12,358	12,349
Employee benefit plans [(c) (e)]	12	97,700	97,126	65,833
Environmental [(a)]	subject to approval	1,240	1,314	1,317
Asset retirement obligations [(a)]	44	3,237	3,287	3,271
Bond issue cost [(a)]	23	3,240	3,276	3,383
Renewable energy standard adjustment [(a)]	5	5,590	9,622	16,088
Flow through accounting [(c)]	35	26,835	25,887	21,837
Decommissioning costs	10	13,702	12,484	—
Other regulatory assets [(a)]	15	13,242	12,454	10,181
		$ 235,477	$ 257,839	$ 201,119
Regulatory liabilities				
Deferred energy and gas costs [(a) (d)]	1	$ 18,094	$ 6,496	$ 6,485
Employee benefit plans [(c) (e)]	12	53,151	53,139	34,355
Cost of removal [(a)]	44	81,449	78,249	67,640
Other regulatory liabilities [(c)]	25	13,845	10,947	8,896
		$ 166,539	$ 148,831	$ 117,376

(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 March 31, 2014 is due to a decrease in the discount rate and a change in the mortality tables used in employee benefit plan estimates.

(5) MATERIALS, SUPPLIES AND FUEL

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

	March 31, 2015	December 31, 2014	March 31, 2014
Materials and supplies	$ 52,429	$ 49,555	$ 50,727
Fuel - Electric Utilities	6,780	6,637	7,218
Natural gas in storage held for distribution	7,417	34,999	8,242
Total materials, supplies and fuel	$ 66,626	$ 91,191	$ 66,187

(6) EARNINGS PER SHARE

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

	Three Months Ended March 31,	
	2015	2014
Net income (loss) available for common stock	$ 47,894	$ 48,118
Weighted average shares - basic	44,541	44,330
Dilutive effect of:		
Equity compensation	119	224
Weighted average shares - diluted	44,660	44,554

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

	Three Months Ended March 31,	
	2015	2014
Equity compensation	107	46
Anti-dilutive shares	107	46

(7) 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:

	March 31, 2015		December 31, 2014		March 31, 2014	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$ 102,600	$ 22,300	$ 75,000	$ 35,000	$ 100,000	$ 27,700

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially 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 March 31, 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. In accordance with the terms of the agreement, the $275 million Corporate term loan is classified as Long-Term Debt as of March 31, 2015. The additional $25 million, less interest and fees, will be 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 March 31, 2015	Covenant Requirement	
Recourse Leverage Ratio	55%	Less than	65%

As of March 31, 2015, we were in compliance with this covenant.

(8) 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.

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 9.

Oil and Gas

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

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue in the accompanying Condensed Consolidated Statements of Income (Loss).

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

	March 31, 2015		December 31, 2014		March 31, 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)]	305,000	5,367,500	334,500	6,582,500	442,500	8,296,250
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	$ —	$ —	$ —	$ —	$ —	$ —

(a) Crude oil in Bbls, natural gas in MMBtus.
(b) Refers to the tenor of the derivative instrument. Assets and liabilities are classified as current/non-current based on the production month hedged and the corresponding settlement of the derivative instrument.

Based on March 31, 2015, prices a $9.9 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:

	March 31, 2015		December 31, 2014		March 31, 2014	
	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	17,280,000	69	19,370,000	72	16,140,000	80
Natural gas options purchased	1,320,000	12	4,020,000	8	1,320,000	12
Natural gas basis swaps purchased	15,735,000	57	12,005,000	60	14,575,000	69

(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):

	March 31, 2015	December 31, 2014	March 31, 2014
Derivative assets, current	$ —	$ —	$ 1,846
Derivative assets, non-current	$ —	$ —	$ —
Derivative liabilities, non-current	$ —	$ —	$ —
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$ 21,606	$ 18,740	$ 4,420

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:

	March 31, 2015 Interest Rate Swaps [(a)]	December 31, 2014 Interest Rate Swaps [(a)]	March 31, 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	1.75	2.00	2.75
Derivative liabilities, current	$ 3,342	$ 3,340	$ 3,498
Derivative liabilities, non-current	$ 2,143	$ 2,680	$ 4,805

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

Three Months Ended March 31, 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	$ (91)	Interest expense	$ (894)		$ —
Commodity derivatives	(3,473)	Revenue	(311)		—
Total	$ (3,564)		$ (1,205)		$ —

(9) 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 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 Chicago Mercantile Exchange pricing for similar instruments.

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 10:

	As of March 31, 2015				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$ —	$ —	$ —	$ —	$ —
Basis Swaps -- Oil	—	8,096	—	(8,096)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	6,526	—	(6,526)	—
Commodity derivatives — Utilities	—	1,184	—	(1,184)	—
Total	$ —	$ 15,806	$ —	$ (15,806)	$ —
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$ —	$ —	$ —	$ —	$ —
Basis Swaps -- Oil	—	2	—	(2)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	256	—	(256)	—
Commodity derivatives — Utilities	—	22,002	—	(22,002)	—
Interest rate swaps	—	5,485	—	—	5,485
Total	$ —	$ 27,745	$ —	$ (22,260)	$ 5,485

	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 March 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	—	7	—	(7)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	490	—	(490)	—
Commodity derivatives — Utilities	—	3,226	—	(1,380)	1,846
Total	$ —	$ 3,723	$ —	$ (1,877)	$ 1,846
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$ —	$ —	$ —	$ —	$ —
Basis Swaps -- Oil	—	1,983	—	(1,983)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	2,114	—	(2,114)	—
Commodity derivatives — Utilities	—	6,919	—	(6,919)	—
Interest rate swaps	—	8,303	—	—	8,303
Total	$ —	$ 19,319	$ —	$ (11,016)	$ 8,303

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 reflecting the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions; however, the amounts do not include net cash collateral on deposit in margin accounts at March 31, 2015, December 31, 2014, and March 31, 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 8.

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

As of March 31, 2015

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

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 March 31, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 30	$ —
Commodity derivatives	Derivative assets — non-current	466	—
Commodity derivatives	Derivative liabilities — current	—	3,187
Commodity derivatives	Derivative liabilities — non-current	—	910
Interest rate swaps	Derivative liabilities — current	—	3,498
Interest rate swaps	Derivative liabilities — non-current	—	4,805
Total derivatives designated as hedges		$ 496	$ 12,400
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,846	$ —
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	5,539
Interest rate swaps	Derivative liabilities — current	—	—
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$ 1,846	$ 5,539

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows (in thousands) as of:

	March 31, 2015		December 31, 2014		March 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$ 63,385	$ 63,385	$ 21,218	$ 21,218	$ 17,641	$ 17,641
Restricted cash and equivalents [(a)]	$ 2,191	$ 2,191	$ 2,056	$ 2,056	$ 2	$ 2
Notes payable [(a)]	$ 102,600	$ 102,600	$ 75,000	$ 75,000	$ 100,000	$ 100,000
Long-term debt, including current maturities [(b)]	$ 1,542,658	$ 1,767,113	$ 1,542,589	$ 1,734,555	$ 1,396,949	$ 1,541,727

(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.

(11) OTHER COMPREHENSIVE INCOME (LOSS)

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

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI Three Months Ended March 31, 2015	Amount Reclassified from AOCI Three Months Ended March 31, 2014
Gains (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ 1,437	$ 894
Commodity contracts	Revenue	(3,932)	311
		(2,495)	1,205
Income tax	Income tax benefit (expense)	1,254	(425)
Reclassification adjustments related to cash flow hedges, net of tax		$ (1,241)	$ 780
Amortization of defined benefit plans:			
Prior service cost	Utilities - Operations and maintenance	$ (27)	$ (25)
	Non-regulated energy operations and maintenance	(28)	12
Actuarial gain (loss)	Utilities - Operations and maintenance	454	157
	Non-regulated energy operations and maintenance	251	85
		650	229
Income tax	Income tax benefit (expense)	(228)	(81)
Reclassification adjustments related to defined benefit plans, net of tax		$ 422	$ 148

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)
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)

(12) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three months ended	March 31, 2015	March 31, 2014
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$ 33,534	$ 40,939
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)	$ (10,909)	$ (11,452)
Income taxes, net	$ (2)	$ 4

(13) 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 March 31, 2015	Three Months Ended March 31, 2014
Service cost	$ 1,494	$ 1,362
Interest cost	3,880	3,963
Expected return on plan assets	(4,867)	(4,516)
Prior service cost	15	16
Net loss (gain)	2,759	1,201
Net periodic benefit cost	$ 3,281	$ 2,026

Defined Benefit Postretirement Healthcare Plans

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

	Three Months Ended March 31,	
	2015	2014
Service cost	$ 464	$ 425
Interest cost	450	479
Expected return on plan assets	(33)	(21)
Prior service cost (benefit)	(107)	(107)
Net loss (gain)	102	40
Net periodic benefit cost	$ 876	$ 816

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended March 31,	
	2015	2014
Service cost	$ 491	$ 374
Interest cost	364	362
Prior service cost	1	1
Net loss (gain)	270	124
Net periodic benefit cost	$ 1,126	$ 861

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 Three Months Ended March 31, 2015	Additional Contributions Anticipated for 2015	Contributions Anticipated for 2016
Defined Benefit Pension Plans	$ —	$ 10,200	$ 10,200
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 939	$ 2,816	$ 4,026
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 372	$ 1,115	$ 1,544

(14) 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 except for those described below.

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 March 31, 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 March 31, 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 March 31, 2015, the restricted net assets at our Utilities Group were approximately $338 million.

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 36,000 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 electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three months ended March 31, 2015 and 2014, and our financial condition as of March 31, 2015, December 31, 2014 and March 31, 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 53.

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.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014. Net income (loss) for the three months ended March 31, 2015 was $48 million, or $1.07 per share, compared to Net income (loss) of $48 million, or $1.08 per share, reported for the same period in 2014.

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

	Three Months Ended March 31,		
	2015	2014	Variance
Revenue			
Utilities	$ 424,049	$ 441,439	$ (17,390)
Non-regulated Energy	49,875	52,696	(2,821)
Inter-company eliminations	(31,937)	(33,966)	2,029
	$ 441,987	$ 460,169	$ (18,182)
Net income (loss)			
Electric Utilities	$ 18,929	$ 14,575	$ 4,354
Gas Utilities	22,212	24,698	(2,486)
Utilities	41,141	39,273	1,868
Power Generation	8,145	8,073	72
Coal Mining	3,010	2,464	546
Oil and Gas	(5,071)	(2,022)	(3,049)
Non-regulated Energy	6,084	8,515	(2,431)
Corporate activities and eliminations	669	330	339
Net income (loss)	$ 47,894	$ 48,118	$ (224)

Overview of Business Segments and Corporate Activity

Utilities Group

- Gas Utilities experienced milder weather during the three months ended March 31, 2015 compared to the three months ended March 31, 2014. Heating degree days were 9% lower for the three months ended March 31, 2015, compared to the same period in 2014. Heating degree days for the three months ended March 31, 2015 were 4% higher than normal, compared to 14% higher than normal for the same period in 2014.

- On April 15, 2015, we filed a request for approval with the WPSC of our $17 million purchase agreement to acquire Energy West, Wyoming, a deal previously announced on October 14, 2014. Energy West is a gas utility serving approximately 6,700 customers, in Cody, Ralston, and Meeteetse, Wyoming. The purchase also includes a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory. A hearing is scheduled with the WPSC on May 14, 2015. We have requested approval from the WPSC to close on the acquisition on June 1, 2015.

- 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 will begin in the second 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.

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC 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. We are awaiting approval of the CPCN from the WPSC. Black Hills Power received approval on November 6, 2014 from the SDPUC for a permit to construct the South Dakota portion of this line. Assuming timely receipt of remaining approvals, Black Hills Power plans to commence construction in the third quarter of 2015.

- On May 5, 2014, Colorado Electric issued an all-source generation request, including up to 60 megawatts of eligible renewable energy resources to serve its customers in southern Colorado. Our power generation segment submitted solar and wind bids in response to the request. An independent evaluator submitted a report to the CPUC confirming the ranking of the bids. On February 27, 2015 the Commission determined that none of the renewable bids were cost effective. Colorado Electric submitted a request for reconsideration on March 19, 2015. On April 16, 2015, the Commission deliberated these requests filed by the company and various parties to the initial decision. The Commission declined to change its decision. In their written order, the commission noted precedent allowing utilities to secure new bid pricing. Colorado Electric, at it's discretion, has sixty days to renegotiate bids and submit a revised contract or contacts for approval. Colorado Electric is currently reviewing its options.

Non-regulated Energy Group

- Our Oil and Gas segment was impacted by lower commodity prices for crude oil and natural gas for the three months ended March 31, 2015 compared to the same period in 2014. The average hedged price received for natural gas decreased by 34% for the three months ended March 31, 2015 compared to the same period in 2014. The average hedged price received for oil decreased by 26% for the three months ended March 31, 2015 compared to the same period in 2014. Oil and Gas production volumes increased 23% for the three months ended March 31, 2015 compared to the same period 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. We did not record a ceiling test impairment for the three months ended March 31, 2015. However, using our current reserves information, a ceiling impairment charge could occur in 2015 if commodity prices for crude oil and natural gas remain at current low levels.

- Our southern Piceance Basin drilling program continued with three Mancos Shale wells placed on production (one in January 2015 and two in February 2015). Production results to date from these wells have been favorable, and exceeded our expectations.

- Our Oil and Gas segment contracted for two additional drilling rigs to support drilling operations in the southern Piceance Basin. Drilling operations are ongoing for 10 additional horizontal wells on three separate surface pads. Due to the partial carryover of 2014 planned Mancos and other drilling capital to 2015, and the addition of one more Mancos well to the 2015 drilling plan, we have increased our planned 2015 capital expenditures to $167 million from $123 million.

Corporate Activities

- 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 March 31,		
	2015	2014	Variance
	(in thousands)		
Revenue — electric	$ 169,917	$ 168,365	$ 1,552
Revenue — gas	16,481	13,737	2,744
Total revenue	186,398	182,102	4,296
Fuel, purchased power and cost of gas — electric	67,690	78,418	(10,728)
Purchased gas — gas	10,098	8,274	1,824
Total fuel, purchased power and cost of gas	77,788	86,692	(8,904)
Gross margin — electric	102,227	89,947	12,280
Gross margin — gas	6,383	5,463	920
Total gross margin	108,610	95,410	13,200
Operations and maintenance	43,984	42,601	1,383
Depreciation and amortization	21,044	19,086	1,958
Total operating expenses	65,028	61,687	3,341
Operating income	43,582	33,723	9,859
Interest expense, net	(13,833)	(12,013)	(1,820)
Other income (expense), net	69	256	(187)
Income tax benefit (expense)	(10,889)	(7,391)	(3,498)
Net income (loss)	$ 18,929	$ 14,575	$ 4,354

Revenue - Electric (in thousands)	Three Months Ended March 31, 2015	2014
Residential:		
Black Hills Power	$ 20,140	$ 20,061
Cheyenne Light	10,265	9,673
Colorado Electric	24,570	24,679
Total Residential	54,975	54,413
Commercial:		
Black Hills Power	24,741	21,528
Cheyenne Light	15,820	14,394
Colorado Electric	22,164	21,890
Total Commercial	62,725	57,812
Industrial:		
Black Hills Power	8,299	7,335
Cheyenne Light	8,626	7,224
Colorado Electric	10,756	9,038
Total Industrial	27,681	23,597
Municipal:		
Black Hills Power	858	792
Cheyenne Light	516	454
Colorado Electric	3,062	3,307
Total Municipal	4,436	4,553
Total Retail Revenue - Electric	149,817	140,375
Contract Wholesale:		
Total Contract Wholesale - Black Hills Power	5,420	5,598
Off-system Wholesale:		
Black Hills Power	6,635	9,075
Cheyenne Light	1,961	2,387
Colorado Electric	84	2,082
Total Off-system Wholesale	8,680	13,544
Other Revenue:		
Black Hills Power	4,190	6,878
Cheyenne Light	475	753
Colorado Electric	1,335	1,217
Total Other Revenue	6,000	8,848
Total Revenue - Electric	$ 169,917	$ 168,365

Quantities Generated and Purchased (in MWh)	Three Months Ended March 31, 2015	2014
Generated —		
Coal-fired:		
Black Hills Power [(a)]	376,834	417,248
Cheyenne Light [(b)]	194,716	169,789
Total Coal-fired	571,550	587,037
Natural Gas and Oil:		
Black Hills Power	2,878	2,308
Cheyenne Light	2,839	—
Colorado Electric [(c)]	3,492	18,068
Total Natural Gas and Oil	9,209	20,376
Wind:		
Colorado Electric	9,091	14,329
Total Wind	9,091	14,329
Total Generated:		
Black Hills Power	379,712	419,556
Cheyenne Light	197,555	169,789
Colorado Electric	12,583	32,397
Total Generated	589,850	621,742
Purchased —		
Black Hills Power	438,443	430,801
Cheyenne Light	187,779	207,318
Colorado Electric	472,187	470,101
Total Purchased	1,098,409	1,108,220
Total Generated and Purchased:		
Black Hills Power	818,155	850,357
Cheyenne Light	385,334	377,107
Colorado Electric	484,770	502,498
Total Generated and Purchased	1,688,259	1,729,962

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(a) Decrease reflects the retirement of Neil Simpson I on March 21, 2014.
(b) Increase is due to purchasing spinning reserve in the current year compared to carrying spinning reserve in the prior year.
(c) Decrease in 2015 generation is primarily driven by commodity prices that impacted power marketing sales.

Quantity (in MWh)	Three Months Ended March 31, 2015	2014
Residential:		
Black Hills Power	146,963	171,311
Cheyenne Light	67,499	70,656
Colorado Electric	157,214	153,632
Total Residential	371,676	395,599
Commercial:		
Black Hills Power	195,078	184,448
Cheyenne Light	131,103	126,412
Colorado Electric	165,081	158,179
Total Commercial	491,262	469,039
Industrial:		
Black Hills Power	111,859	100,851
Cheyenne Light	111,096	90,724
Colorado Electric	118,107	90,116
Total Industrial	341,062	281,691
Municipal:		
Black Hills Power	7,700	7,686
Cheyenne Light	2,550	2,493
Colorado Electric	28,113	26,687
Total Municipal	38,363	36,866
Total Retail Quantity Sold	1,242,363	1,183,195
Contract Wholesale:		
Total Contract Wholesale - Black Hills Power [(a)]	84,271	95,228
Off-system Wholesale:		
Black Hills Power	245,638	254,796
Cheyenne Light	48,872	52,356
Colorado Electric [(b)]	2,469	30,746
Total Off-system Wholesale	296,979	337,898
Total Quantity Sold:		
Black Hills Power	791,509	814,320
Cheyenne Light	361,120	342,641
Colorado Electric	470,984	459,360
Total Quantity Sold	1,623,613	1,616,321
Other Uses, Losses or Generation, net [(c)]:		
Black Hills Power	26,646	36,037
Cheyenne Light	24,214	34,466
Colorado Electric	13,786	43,138
Total Other Uses, Losses and Generation, net	64,646	113,641
Total Energy	1,688,259	1,729,962

(a) Decrease is driven by load requirements related to a Wygen III unit-contingent PPA.
(b) Decrease in 2015 generation is primarily driven by commodity prices that impacted power marketing sales.
(c) Includes company uses, line losses, and excess exchange production.

Degree Days	Three Months Ended March 31, 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	2,873	(11)%	(16)%	3,410	6%
Cheyenne Light	2,651	(12)%	(17)%	3,206	6%
Colorado Electric	2,398	(8)%	(10)%	2,670	2%
Combined [(a)]	2,610	(10)%	(14)%	3,028	5%

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

Electric Utilities Power Plant Availability	Three Months Ended March 31, 2015	2014
Coal-fired plants	91.3%	95.5%
Other plants [(a)]	95.7%	78.1%
Total availability	94.1%	86.6%

(a) The three months ended March 31, 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 system. The following table summarizes certain operating information for these natural gas distribution operations:

	Three Months Ended March 31,	
	2015	2014
Revenue - Natural Gas (in thousands):		
Residential	$ 8,712	$ 8,224
Commercial	4,954	3,977
Industrial	1,900	1,285
Other Sales Revenue	915	251
Total Revenue - Natural Gas	$ 16,481	$ 13,737
Gross Margin (in thousands):		
Residential	$ 3,778	$ 3,605
Commercial	1,428	1,332
Industrial	262	275
Other Gross Margin	915	251
Total Gross Margin	$ 6,383	$ 5,463
Volumes Sold (Dth):		
Residential	940,407	1,035,177
Commercial	670,589	564,394
Industrial	301,277	255,927
Total Volumes Sold	1,912,273	1,855,498

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014: Net income for the Electric Utilities was $19 million for the three months ended March 31, 2015, compared to Net income of $15 million for the three months ended March 31, 2014, as a result of:

Gross margin increased primarily due to a return on additional investment in our generating facilities which increased electric gross margins by $9.4 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 $2.5 million. Colorado Electric also 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. Partially offsetting these increases was a negative weather impact on electric and gas residential retail margins of $3.2 million driven by a 14% 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 Oct. 1, 2014, and an increase in allowance for uncollectible account expense.

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 Oct. 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 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 March 31,		
	2015	2014	Variance
	(in thousands)		
Revenue:			
Natural gas — regulated	$ 229,148	$ 251,232	$ (22,084)
Other — non-regulated services	8,503	8,105	398
Total revenue	237,651	259,337	(21,686)
Cost of sales			
Natural gas — regulated	152,285	170,774	(18,489)
Other — non-regulated services	3,913	3,722	191
Total cost of sales	156,198	174,496	(18,298)
Gross margin	81,453	84,841	(3,388)
Operations and maintenance	35,432	35,378	54
Depreciation and amortization	7,046	6,521	525
Total operating expenses	42,478	41,899	579
Operating income (loss)	38,975	42,942	(3,967)
Interest expense, net	(3,809)	(3,853)	44
Other income (expense), net	(11)	(17)	6
Income tax benefit (expense)	(12,943)	(14,374)	1,431
Net income (loss)	$ 22,212	$ 24,698	$ (2,486)

Revenue (in thousands)	Three Months Ended March 31, 2015	2014
Residential:		
Colorado	$ 25,736	$ 23,687
Nebraska	56,444	62,892
Iowa	46,366	54,764
Kansas	29,328	33,277
Total Residential	157,874	174,620
Commercial:		
Colorado	5,097	4,697
Nebraska	18,212	20,066
Iowa	21,629	25,914
Kansas	11,066	11,671
Total Commercial	56,004	62,348
Industrial:		
Colorado	29	77
Nebraska	317	208
Iowa	1,255	1,172
Kansas	1,741	1,086
Total Industrial	3,342	2,543
Transportation:		
Colorado	365	325
Nebraska	5,396	5,730
Iowa	1,662	1,761
Kansas	2,501	2,493
Total Transportation	9,924	10,309
Other Sales Revenue:		
Colorado	43	31
Nebraska	657	703
Iowa	139	152
Kansas	1,165	526
Total Other Sales Revenue	2,004	1,412
Total Regulated Revenue	229,148	251,232
Non-regulated Services	8,503	8,105
Total Revenue	$ 237,651	$ 259,337

Gross Margin (in thousands)	Three Months Ended March 31, 2015	2014
Residential:		
Colorado	$ 6,337	$ 6,372
Nebraska	18,990	20,889
Iowa	13,898	15,210
Kansas	11,478	11,584
Total Residential	50,703	54,055
Commercial:		
Colorado	1,040	1,060
Nebraska	4,669	5,163
Iowa	4,636	5,225
Kansas	3,387	3,183
Total Commercial	13,732	14,631
Industrial:		
Colorado	21	30
Nebraska	81	68
Iowa	81	85
Kansas	393	236
Total Industrial	576	419
Transportation:		
Colorado	365	326
Nebraska	5,396	5,731
Iowa	1,662	1,761
Kansas	2,501	2,493
Total Transportation	9,924	10,311
Other Sales Margins:		
Colorado	43	31
Nebraska	657	702
Iowa	139	152
Kansas	1,089	157
Total Other Sales Margins	1,928	1,042
Total Regulated Gross Margin	76,863	80,458
Non-regulated Services	4,590	4,383
Total Gross Margin	$ 81,453	$ 84,841

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended March 31, 2015	2014
Residential:		
Colorado	2,946,805	3,021,434
Nebraska	5,958,956	6,986,293
Iowa	5,516,037	6,643,044
Kansas	3,353,814	3,881,555
Total Residential	17,775,612	20,532,326
Commercial:		
Colorado	617,198	635,690
Nebraska	2,180,694	2,475,156
Iowa	2,880,091	3,485,692
Kansas	1,435,504	1,541,967
Total Commercial	7,113,487	8,138,505
Industrial:		
Colorado	2,402	10,325
Nebraska	45,700	26,965
Iowa	191,005	193,863
Kansas [(a)] [(b)]	324,779	180,087
Total Industrial	563,886	411,240
Wholesale and Other:		
Kansas [(b)]	13,975	68,633
Total Wholesale and Other	13,975	68,633
Total Distribution Quantities Sold	25,466,960	29,150,704
Transportation:		
Colorado	380,049	330,344
Nebraska	9,049,775	9,963,219
Iowa	6,088,049	6,157,366
Kansas	4,297,352	4,827,137
Total Transportation	19,815,225	21,278,066
Total Distribution Quantities Sold and Transportation	45,282,185	50,428,770

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(a) Increase is primarily due to a large customer's sales volumes compared to the prior year and from a classification change in customer class.
(b) Decrease from prior year is primarily due a change in customer class.

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

	Three Months Ended March 31,				
	2015			2014	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Colorado	2,535	(9)%	(11)%	2,859	2%
Nebraska	3,014	—%	(8)%	3,272	7%
Iowa	3,834	13%	(8)%	4,174	19%
Kansas [(a)]	2,322	(6)%	(14)%	2,689	8%
Combined [(b)]	3,222	4%	(9)%	3,524	14%

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(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 March 31, 2015 Compared to the Three Months Ended March 31, 2014: Net income for the Gas Utilities was $22 million for the three months ended March 31, 2015, compared to Net income of $25 million for the three months ended March 31, 2014, as a result of:

<u>Gross margin</u> decreased primarily due to a $5.3 million impact from milder weather than in the same period in the prior year. Heating degree days were 9% lower for the three months ended March 31, 2015, compared to the same period in the prior year and 4% higher than normal in the current year, compared to 14% higher than normal in the prior year. Partially offsetting this weather impact was a $1.2 million increase from base rate adjustments at Kansas Gas which were effective January 1, 2015, and a $0.6 million increase from year-over-year customer growth.

<u>Operations and maintenance</u> was comparable to the prior year reflecting increases in property taxes and allowance for uncollectible account expense, offset by a decrease in employee costs.

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

<u>Interest expense, net</u> was comparable to the same period in the prior year.

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

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

Regulatory Matters — Utilities Group

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

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(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. 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 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 a return on infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The implementation of the rider allows Colorado Electric to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

Capital Investment Recovery Surcharge filings

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

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(a) On April 6, 2015, Nebraska Gas filed with the NPSC for a capital investment recovery surcharge increase of $1.5 million. Approval is expected in July, 2015.

(b) On March 17, 2015, Iowa Gas filed with the IUB for a capital investment recovery surcharge increase of $0.9 million. Approval is expected in June 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 March 31,		
	2015	2014	Variance
	(in thousands)		
Revenue	$ 22,674	$ 22,348	$ 326
Operations and maintenance	7,828	7,677	151
Depreciation and amortization	1,134	1,209	(75)
Total operating expense	8,962	8,886	76
Operating income	13,712	13,462	250
Interest expense, net	(886)	(928)	42
Other (expense) income, net	(2)	(9)	7
Income tax (expense) benefit	(4,679)	(4,452)	(227)
Net income (loss)	$ 8,145	$ 8,073	$ 72

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

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended March 31,	
	2015	2014
Quantities Sold, Generated and Purchased (MWh) [(a)]		
Sold		
Black Hills Colorado IPP	284,491	285,956
Black Hills Wyoming [(b)]	159,558	140,608
Total Sold	444,049	426,564
Generated		
Black Hills Colorado IPP	284,491	285,956
Black Hills Wyoming	137,973	140,678
Total Generated	422,464	426,634
Purchased		
Black Hills Wyoming [(b)]	24,392	989
Total Purchased	24,392	989

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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 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 March 31,	
	2015	2014
Contracted power plant fleet availability:		
Coal-fired plant	98.2%	99.3%
Natural gas-fired plants	98.9%	97.9%
Total availability	98.7%	98.2%

Results of Operations for Power Generation for the Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014: Net income for the Power Generation segment was $8.1 million for the three months ended March 31, 2015, compared to Net income of $8.1 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 is 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 March 31,		
	2015	2014	Variance
	(in thousands)		
Revenue	$ 15,934	$ 15,498	$ 436
Operations and maintenance	9,904	10,131	(227)
Depreciation, depletion and amortization	2,503	2,690	(187)
Total operating expenses	12,407	12,821	(414)
Operating income (loss)	3,527	2,677	850
Interest (expense) income, net	(89)	(103)	14
Other income, net	585	603	(18)
Income tax benefit (expense)	(1,013)	(713)	(300)
Net income (loss)	$ 3,010	$ 2,464	$ 546

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

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
Tons of coal sold	1,019	1,087
Cubic yards of overburden moved	1,413	910
Revenue per ton	$ 15.64	$ 14.26

Results of Operations for Coal Mining for the Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014: Net income for the Coal Mining segment was $3.0 million for the three months ended March 31, 2015, compared to Net income of $2.5 million for the same period in 2014 as a result of:

Revenue increased primarily due to a 10% increase in price per ton sold, partially offset by a 6% decrease in tons sold. The increase in pricing was driven by the price re-opener on our 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 unplanned customer outages, and the closure of Neil Simpson 1 in March 2014. 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 decreased primarily due to mining efficiencies resulting in reduced major maintenance, blasting and lower fuel costs, partially offset by a higher overburden stripping ratio and a favorable coal tax adjustment recognized in 2014.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets driven by a lower net asset base.

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

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

Income tax benefit (expense): The effective tax rate in 2015 is higher due primarily to the reduced impact of the tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended March 31, 2015	2014	Variance
	(in thousands)		
Revenue	$ 11,267	$ 14,850	$ (3,583)
Operations and maintenance	10,917	11,139	(222)
Depreciation, depletion and amortization	8,095	6,633	1,462
Total operating expenses	19,012	17,772	1,240
Operating income (loss)	(7,745)	(2,922)	(4,823)
Interest income (expense), net	(384)	(455)	71
Other income (expense), net	(223)	38	(261)
Income tax benefit (expense)	3,281	1,317	1,964
Net income (loss)	$ (5,071)	$ (2,022)	$ (3,049)

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

	Three Months Ended March 31, 2015	2014
Production:		
Bbls of oil sold	80,730	74,262
Mcf of natural gas sold	2,254,042	1,759,964
Bbls of NGL sold	28,770	27,041
Mcf equivalent sales	2,911,043	2,367,782

	Three Months Ended March 31, 2015	2014
Average price received: (a) (b)		
Oil/Bbl	$ 66.86	$ 90.75
Gas/Mcf	$ 2.20	$ 3.35
NGL/Bbl	$ 13.74	$ 49.02
Depletion expense/Mcfe	$ 2.40	$ 2.25

(a) Net of hedge settlement gains and losses.
(b) Based on our quarterly ceiling test under the full cost accounting rules of the SEC, no impairment charge was necessary as of March 31, 2015. If crude oil and natural gas prices remain at or near the current low levels, a ceiling test impairment charge could occur in 2015.

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

	Three Months Ended March 31, 2015				Three Months Ended March 31, 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	$ 1.58	$ 1.30	$ 0.37	$ 3.25	$ 1.54	$ 1.20	$ 0.63	$ 3.37
Piceance	0.33	2.48	0.20	3.01	(0.06)	1.28	0.57	1.79
Powder River	2.89	—	0.56	3.45	2.36	—	1.34	3.70
Williston	0.24	—	0.09	0.33	0.67	—	1.90	2.57
All other properties	1.24	—	0.34	1.58	1.61	—	0.02	1.63
Total weighted average	$ 1.19	$ 1.35	$ 0.31	$ 2.85	$ 1.19	$ 0.81	$ 0.74	$ 2.74

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

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, 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. The higher costs for 2015 are due to lower volumes delivered to the plant for the first half of the quarter.

Results of Operations for Oil and Gas for the Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014: Net loss for the Oil and Gas segment was $5.1 million for the three months ended March 31, 2015, compared to Net loss of $2.0 million for the same period in 2014 as a result of:

Revenue decreased primarily due to lower commodity market prices for both crude oil and natural gas resulting in a 26% decrease in the average hedged price received for crude oil sold, and a 34% decrease in the average hedged price received for natural gas sold. A production increase of 23%, 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 decreased primarily due to lower production taxes and ad valorem taxes on lower revenue and lower employee costs, partially offset by higher lease and field operation expenses from non-operated wells.

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

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

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

Income tax (expense) benefit: The effective tax rate in 2015 is comparable to the same period in the prior year.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended March 31, 2015 Compared to the Three Months Ended March 31, 2014: Net income for Corporate was $0.7 million for the three months ended March 31, 2015, compared to Net income of $0.3 million for the three months ended March 31, 2014 as a result of:

- The income for the three months ended March 31, 2015, included lower interest expense compared to the three months ended March 31, 2014, primarily driven by favorable margins on base rate borrowings on our Revolving Credit Facility. Our Revolving Credit Facility agreement was amended and extended on May 29, 2014 with improved margins on base rate borrowings of 0.25% compared to the agreement it replaced.

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 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.

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 three months ended March 31 (in thousands):

Cash provided by (used in):	2015	2014	Increase (Decrease)
Operating activities	$ 151,487	$ 98,098	$ 53,389
Investing activities	$ (117,871)	$ (86,829)	$ (31,042)
Financing activities	$ 8,551	$ (1,469)	$ 10,020

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

Operating Activities

Net cash provided by operating activities was $151 million for the three months ended March 31, 2015, compared to net cash provided by operating activities of $98 million for the same period in 2014 for a variance of $53 million. The variance was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were comparable for the three months ended March 31, 2015 to the same period in the prior year.

- Net inflows from operating assets and liabilities were $29 million for the three months ended March 31, 2015, compared to net cash outflows of $27 million in the same period in the prior year. This $56 million variance was primarily due to:

    - Cash inflows increased as a result of lower working capital requirements for the three months ended March 31, 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

    - Accrued expenditures decreased primarily at our Oil and Gas segment related to drilling activity for the three months ended March 31, 2015 compared to the same period in the prior year.

Investing Activities

Net cash used in investing activities was $118 million for the three months ended March 31, 2015, compared to net cash used in investing activities of $87 million for the same period in 2014. The variance was primarily driven by:

- Capital expenditures of approximately $118 million for the three months ended March 31, 2015, compared to $84 million for the three months ended March 31, 2014. The increase is related primarily to higher capital expenditures at our Oil and Gas segment driven by drilling activity in the Southern Piceance in the current year. The prior year Oil and Gas segment capital expenditures were affected by weather delays. Offsetting the oil and gas capital expenditure increase 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 three months ended March 31, 2015 was $8.6 million, compared to $1.5 million net cash used in financing activities for the same period in 2014. The variance was primarily driven by:

- Net short-term borrowings under the revolving credit facility for the three months ended March 31, 2015 increased primarily to fund the increase in overall capital expenditures.

Dividends

Dividends paid on our common stock totaled $18 million for the three months ended March 31, 2015, or $0.405 per share. On April 27, 2015, our board of directors declared a quarterly dividend of $0.405 per share payable June 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 May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially 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 are 0.125%, 1.125% and 1.125%, respectively. A commitment fee is charged on the unused amount of the Revolving Credit Facility and is 0.175% based on our credit rating.

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

Credit Facility	Expiration	Current Capacity	Borrowings at March 31, 2015	Letters of Credit at March 31, 2015	Available Capacity at March 31, 2015
Revolving Credit Facility	May 29, 2019	$ 500	$ 103	$ 22	$ 375

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit, and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of March 31, 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 1.75 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 $5.5 million at March 31, 2015.

Financing Activities

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, will be used for general corporate purposes. The cost of the borrowing under the new term loan will be 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 amending and extending our Revolving Credit Facility for an additional year.
- Evaluate the conversion of our $300 million variable-rate Corporate term loan to fixed rate 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 March 31, 2015, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $338 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 March 31, 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 filed with the SEC.

Credit Ratings

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

The following table represents the credit ratings and outlook of BHC at March 31, 2015:

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

The following table represents the credit ratings of Black Hills Power at March 31, 2015:

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

Capital Requirements

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

	Expenditures for the Three Months Ended March 31, 2015 (a)	Total 2015 Planned Expenditures (b)	Total 2016 Planned Expenditures	Total 2017 Planned Expenditures
Utilities:				
Electric Utilities	$ 29,376	$ 229,300	$ 225,400	$ 135,600
Gas Utilities	12,006	83,600	60,100	71,800
Cost of Service Gas	—	—	40,000	50,000
Non-regulated Energy:				
Power Generation	3,465	8,000	2,000	2,600
Coal Mining	4,287	7,000	6,000	6,600
Oil and Gas (c)	47,912	167,000	122,000	120,000
Corporate	1,433	6,100	1,500	3,600
	$ 98,479	$ 501,000	$ 457,000	$ 390,200

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(a) Expenditures for the three months ended March 31, 2015 include the impact of accruals for property, plant and equipment.
(b) Includes actual expenditures for the three months ended March 31, 2015.
(c) Our Oil and Gas segment contracted for two additional drilling rigs to support drilling operations in the southern Piceance Basin. Drilling operations are ongoing for 10 additional horizontal wells on three separate surface pads. Due to the partial carryover of 2014 planned Mancos and other drilling capital to 2015, and the addition of one more Mancos well to the 2015 drilling plan, we have increased our planned 2015 capital expenditures to $167 million from $123 million.

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.

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.

New Accounting Pronouncements

Other than the pronouncements reported in our 2014 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 2 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2014 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2014 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

	March 31, 2015	December 31, 2014	March 31, 2014
Net derivative (liabilities) assets	$ (20,818)	$ (16,914)	$ (3,693)
Cash collateral offset in Derivatives	20,818	16,914	5,539
Cash Collateral included in Other current assets	3,818	3,093	1,917
Net asset (liability) position	$ 3,818	$ 3,093	$ 3,763

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 March 31, 2015, were as follows:

Natural Gas

	March 31,	June 30,	September 30,	December 31,	Total Year
2015					
Swaps - MMBtu	—	1,180,000	955,000	1,000,000	3,135,000
Weighted Average Price per MMBtu	$ —	$ 4.03	$ 4.00	$ 4.04	$ 4.03
2016					
Swaps - MMBtu	585,000	557,500	545,000	545,000	2,232,500
Weighted Average Price per MMBtu	$ 3.87	$ 3.87	$ 3.91	$ 3.90	$ 3.89

Crude Oil

	March 31,	June 30,	September 30,	December 31,	Total Year
2015					
Swaps - Bbls	—	53,000	54,000	48,000	155,000
Weighted Average Price per Bbl	$ —	$ 86.56	$ 80.70	$ 79.56	$ 82.35
2016					
Swaps - Bbls	39,000	39,000	36,000	36,000	150,000
Weighted Average Price per Bbl	$ 84.55	$ 84.55	$ 84.55	$ 84.55	$ 84.55

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

	March 31, 2015	December 31, 2014	March 31, 2014
Net derivative (liabilities) assets	$ 14,364	$ 14,684	$ (3,601)
Cash collateral offset in Derivatives	(14,364)	(14,684)	3,601
Cash Collateral included in Other current assets	3,286	4,392	4,067
Net asset (liability) position	$ 3,286	$ 4,392	$ 4,067

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 and in Note 8 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

	March 31, 2015	December 31, 2014	March 31, 2014
	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(a)]	Designated Interest Rate Swaps [(a)]
Notional	$ 75,000	$ 75,000	$ 75,000
Weighted average fixed interest rate	4.97%	4.97%	4.97%
Maximum terms in years	1.75	2.00	2.75
Derivative liabilities, current	$ 3,342	$ 3,340	$ 3,498
Derivative liabilities, non-current	$ 2,143	$ 2,680	$ 4,805
Pre-tax accumulated other comprehensive income (loss)	$ (5,485)	$ (6,020)	$ (8,303)

(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 March 31, 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 March 31, 2015. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended March 31, 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.

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 and Note 14 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 14 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2014 Annual Report on Form 10-K.

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

There were no unregistered securities sold during the three months ended March 31, 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 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*	Credit Agreement dated April 13, 2015 among Black Hills Corporation, as Borrower, JPMorgan Chase Bank, N. A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant’s Form 8-K filed on April 14, 2015).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.

Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

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

SIGNATURES

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

BLACK HILLS CORPORATION

/s/ David R. Emery

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

/s/ Richard W. Kinzley

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

Dated: May 5, 2015

INDEX TO EXHIBITS

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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.

Exhibit 31.1

CERTIFICATION

I, David R. Emery, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 5, 2015

/S/ DAVID R. EMERY

David R. Emery
Chairman, President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard W. Kinzley, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 5, 2015

/S/ RICHARD W. KINZLEY

Richard W. Kinzley
Senior Vice President and
Chief Financial Officer

Exhibit 32.1

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

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: May 5, 2015

/S/ DAVID R. EMERY
David R. Emery
Chairman, President and
Chief Executive Officer

Exhibit 32.2

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

In connection with the Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Richard W. Kinzley, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: May 5, 2015

/S/ RICHARD W. KINZLEY

Richard W. Kinzley
Senior Vice President and
Chief Financial Officer

Exhibit 95

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

Mine Safety and Health Administration Safety Data

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

Under the recently enacted Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operation, consisting of Wyodak Coal Mine, is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present the following information regarding certain mining safety and health matters for the three month period ended March 31, 2015. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

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

The table below sets forth the total number of citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments received during the three months ended March 31, 2015 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for WRDC, our only mining complex. All citations were abated within 24 hours of issue.

Mine/ MSHA Identification Number	Mine Act Section 104 S&S Citations issued during three months ended March 31, 2015	Mine Act Section 104(b) Orders (#)	Mine Act Section 104(d) Citations and Orders (#)	Mine Act Section 110(b)(2) Violations (#)	Mine Act Section 107(a) Imminent Danger Orders (#)	Total Dollar Value of Proposed MSHA Assessments	Total Number of Mining Related Fatalities (#)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#) (a)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Wyodak Coal Mine - 4800083	2	—	—	—	—	$ 3,253	—	No	—	—	—

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