BLACK HILLS CORP /SD/
Form 10-Q
May 02, 2014

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, 2014

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 29, 2014	
Common stock, $1.00 par value	44,628,586	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
Bopd	Barrels of oil per day
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 currently being constructed in Cheyenne, Wyoming by Cheyenne Light and Black Hills Power. Construction is expected to be completed for this 132 megawatt facility in 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
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013.
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.
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.

IPP	Independent power producer
IRS	United States Internal Revenue Service
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
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent.
MMBtu	Million British thermal units
MMcfd	Millions of cubic feet per day
Moody’s	Moody’s Investors Service, Inc.
MWh	Megawatt-hours
NGL	Natural Gas Liquids (7 Gallons equals 1 Mcfe)
NOL	Net Operating Loss
OTC	Over-the-counter
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 2017.
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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended March 31,	
	2014	2013
	(in thousands, except per share amounts)	
Revenue	$460,169	$380,671
Operating expenses:		
Utilities -		
Fuel, purchased power and cost of natural gas sold	230,468	168,173
Operations and maintenance	71,227	65,690
Non-regulated energy operations and maintenance	22,332	21,329
Depreciation, depletion and amortization	36,083	34,781
Taxes - property, production and severance	10,336	10,380
Other operating expenses	125	472
Total operating expenses	370,571	300,825
Operating income	89,598	79,846
Other income (expense):		
Interest charges -		
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(17,860)	(23,672)
Allowance for funds used during construction - borrowed	270	74
Capitalized interest	257	266
Unrealized gain (loss) on interest rate swaps, net	—	7,456
Interest income	390	285
Allowance for funds used during construction - equity	238	200
Other income (expense), net	592	405
Total other income (expense), net	(16,113)	(14,986)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	73,485	64,860
Equity in earnings (loss) of unconsolidated subsidiaries	(1)	(86)
Income tax benefit (expense)	(25,366)	(21,577)
Net income (loss) available for common stock	$48,118	$43,197
Earnings (loss) per share of common stock:		
Earnings (loss) per share, Basic -		
Total income (loss) per share, Basic	$1.09	$0.98
Earnings (loss) per share, Diluted -		
Total income (loss) per share, Diluted	$1.08	$0.97
Weighted average common shares outstanding:		
Basic	44,330	44,053
Diluted	44,554	44,312

Dividends paid per share of common stock	$0.39	$0.38

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,	
	2014	2013
	(in thousands)	
Net income (loss) available for common stock	$48,118	$43,197
Other comprehensive income (loss), net of tax:		
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $1,307 and $1,117, respectively)	(2,257)	(1,661)
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(425) and $(236), respectively)	780	468
Benefit plan liability adjustments - net gain (loss) (net of tax of $2 and $0, respectively)	(2)	—
Benefit plan liability adjustments - prior service (costs) (net of tax of $(90) and $0, respectively)	164	—
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $4 and $17, respectively)	(9)	(46)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of $(85) and $(192), respectively)	157	503
Other comprehensive income (loss), net of tax	(1,167)	(736)
Comprehensive income (loss) available for common stock	$46,951	$42,461

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, 2014	December 31, 2013	March 31, 2013
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$17,641	$7,841	$12,397
Restricted cash and equivalents	2	2	6,846
Accounts receivable, net	203,625	177,573	168,783
Materials, supplies and fuel	66,187	88,478	64,189
Derivative assets, current	1,846	717	1,630
Income tax receivable, net	1,826	1,460	—
Deferred income tax assets, net, current	25,780	18,889	38,196
Regulatory assets, current	62,946	24,451	23,422
Other current assets	24,563	25,877	28,260
Total current assets	404,416	345,288	343,723
Investments	16,916	16,697	16,545
Property, plant and equipment	4,318,194	4,259,445	3,977,704
Less: accumulated depreciation and depletion	(1,298,398)	(1,269,148)	(1,210,833)
Total property, plant and equipment, net	3,019,796	2,990,297	2,766,871
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,342	3,397	3,565
Derivative assets, non-current	—	—	—
Regulatory assets, non-current	138,173	138,197	181,119
Other assets, non-current	28,925	27,906	21,367
Total other assets, non-current	523,836	522,896	559,447
TOTAL ASSETS	$3,964,964	$3,875,178	$3,686,586

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, 2014	December 31, 2013	March 31, 2013
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$149,681	$130,416	$82,437
Accrued liabilities	145,973	151,277	140,230
Derivative liabilities, current	3,498	3,474	89,112
Accrued income tax, net	—	—	1,157
Regulatory liabilities, current	583	10,727	19,020
Notes payable	100,000	82,500	245,000
Current maturities of long-term debt	—	—	104,637
Total current liabilities	399,735	378,394	681,593
Long-term debt, net of current maturities	1,396,949	1,396,948	936,477
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	466,856	432,287	367,502
Derivative liabilities, non-current	4,805	5,614	15,237
Regulatory liabilities, non-current	116,793	109,429	126,573
Benefit plan liabilities	113,324	111,479	172,353
Other deferred credits and other liabilities	129,083	133,279	125,958
Total deferred credits and other liabilities	830,861	792,088	807,623
Commitments and contingencies (See Notes 7, 8, 13 and 14)			
Stockholders' equity:			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,666,953; 44,550,239; and 44,482,304 shares, respectively	44,667	44,550	44,482
Additional paid-in capital	742,016	742,344	735,000
Retained earnings	570,963	540,244	519,184
Treasury stock, at cost – 37,038; 50,877; and 41,606 shares, respectively	(1,638)	(1,968)	(1,549)
Accumulated other comprehensive income (loss)	(18,589)	(17,422)	(36,224)
Total stockholders' equity	1,337,419	1,307,748	1,260,893
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,964,964	$3,875,178	$3,686,586

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,	
	2014	2013
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$48,118	$43,197
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	36,083	34,781
Deferred financing cost amortization	568	1,095
Stock compensation	3,716	3,778
Unrealized (gain) loss on interest rate swaps, net	—	(7,456)
Deferred income taxes	25,953	20,541
Employee benefit plans	3,703	5,548
Other adjustments, net	5,190	7,087
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	22,291	18,519
Accounts receivable, unbilled revenues and other operating assets	(78,576)	(5,323)
Accounts payable and other current liabilities	29,074	(13,637)
Other operating activities, net	1,978	1,102
Net cash provided by operating activities	98,098	109,232
Investing activities:		
Property, plant and equipment additions	(83,609)	(63,939)
Other investing activities	(3,220)	1,030
Net cash provided by (used in) investing activities	(86,829)	(62,909)
Financing activities:		
Dividends paid on common stock	(17,399)	(16,882)
Common stock issued	881	2,426
Short-term borrowings - issuances	86,800	78,500
Short-term borrowings - repayments	(69,300)	(110,500)
Long-term debt - repayments	—	(1,737)
Other financing activities	(2,451)	(1,195)
Net cash provided by (used in) financing activities	(1,469)	(49,388)
Net change in cash and cash equivalents	9,800	(3,065)
Cash and cash equivalents, beginning of period	7,841	15,462
Cash and cash equivalents, end of period	$17,641	$12,397

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.

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2013 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 2013 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, 2014, December 31, 2013, and March 31, 2013 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, 2014 and March 31, 2013, and our financial condition as of March 31, 2014, December 31, 2013, and March 31, 2013, 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 and do not believe that there are any other new accounting pronouncements that have been issued that might have a material impact 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, 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

Three Months Ended March 31, 2013	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$158,483	$4,147	$12,356
Gas	199,812	—	18,483
Non-regulated Energy:			
Power Generation	1,022	19,338	5,644
Coal Mining	6,010	7,573	1,065
Oil and Gas	15,344	—	(53)
Corporate activities [a]	—	—	5,699
Inter-company eliminations	—	(31,058)	3
Total	$380,671	$—	$43,197

(a) Net income (loss) includes a $4.8 million after-tax non-cash mark-to-market gain for the three months ended March 31, 2013 on certain interest rate swaps.

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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, 2014	December 31, 2013	March 31, 2013
Utilities:			
Electric [(a)]	$2,572,616	$2,525,947	$2,367,014
Gas	842,660	805,617	752,468
Non-regulated Energy:			
Power Generation [(a)]	90,643	95,692	115,708
Coal Mining	74,523	78,825	82,839
Oil and Gas	295,083	288,366	255,786
Corporate activities	89,439	80,731	112,771
Total assets	$3,964,964	$3,875,178	$3,686,586

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

(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, 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

December 31, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$52,437	$23,823	$(666)	$75,594
Gas Utilities	49,162	41,195	(558)	89,799
Power Generation	1,722	—	—	1,722
Coal Mining	1,711	—	—	1,711
Oil and Gas	8,156	—	(13)	8,143
Corporate	604	—	—	604
Total	$113,792	$65,018	$(1,237)	$177,573

March 31, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$47,896	$21,591	$(623)	$68,864
Gas Utilities	59,024	28,439	(751)	86,712
Power Generation	3	—	—	3
Coal Mining	1,857	—	—	1,857
Oil and Gas	10,340	—	(19)	10,321
Corporate	1,026	—	—	1,026
Total	$120,146	$50,030	$(1,393)	$168,783

(4) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of March 31, 2014	As of December 31, 2013	As of March 31, 2013
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)]	1	$23,935	$16,775	$16,815
Deferred gas cost adjustments and gas price derivatives [(a)]	7	42,925	12,366	8,264
AFUDC [(b)]	45	12,349	12,315	12,335
Employee benefit plans [(c)]	13	65,833	67,059	115,564
Environmental [(a)]	subject to approval	1,317	1,800	1,793
Asset retirement obligations [(a)]	44	3,271	3,266	3,252
Bond issue cost [(a)]	24	3,383	3,419	3,526
Renewable energy standard adjustment [(a)]	5	16,088	14,186	16,325
Flow through accounting [(c)]	35	21,837	20,916	17,308
Other regulatory assets [(a)]	15	10,181	10,546	9,359
		$201,119	$162,648	$204,541
Regulatory liabilities				
Deferred energy and gas costs [(a)]	1	$6,485	$11,708	$21,463
Employee benefit plans [(c)]	13	34,355	34,431	60,214
Cost of removal [(a)]	44	67,640	64,970	56,517
Other regulatory liabilities [(c)]	25	8,896	9,047	7,399
		$117,376	$120,156	$145,593

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(a) Recovery of costs, but 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.

(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, 2014	December 31, 2013	March 31, 2013
Materials and supplies	$50,727	$50,196	$50,401
Fuel - Electric Utilities	7,218	6,213	8,445
Natural gas in storage held for distribution	8,242	32,069	5,343
Total materials, supplies and fuel	$66,187	$88,478	$64,189

(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,	
	2014	2013
Net Income (loss) available for common stock	$48,118	$43,197
Weighted average shares - basic	44,330	44,053
Dilutive effect of:		
Equity compensation	224	259
Weighted average shares - diluted	44,554	44,312

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,	
	2014	2013
Equity compensation	46	40
Anti-dilutive shares	46	40

(7) NOTES PAYABLE

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

	March 31, 2014		December 31, 2013		March 31, 2013	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$100,000	$27,700	$82,500	$22,100	$95,000	$36,500
Term Loan due June 2013	—	—	—	—	150,000	—
Total	$100,000	$27,700	$82,500	$22,100	$245,000	$36,500

The term loan for $150 million was repaid on June 21, 2013.

Debt Covenants

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

	As of March 31, 2014	Covenant Requirement		
Recourse Leverage Ratio	55%	Less than	65	%

As of March 31, 2014, 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 2013 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.

As of March 31, 2014, our credit exposure included an $0.8 million exposure to a non-investment grade energy marketing company. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade rated companies, cooperative utilities and federal agencies. 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.

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Oil and Gas

We produce natural gas 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 over-the-counter swaps, 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. 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, 2014		December 31, 2013		March 31, 2013	
	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)]	442,500	8,296,250	412,500	7,082,500	522,000	10,633,000
Maximum terms in months [(b)]	1	1	3	1	9	6
Derivative assets, current	$—	$—	$55	$—	$821	$287
Derivative assets, non-current	$—	$—	$—	$—	$—	$—
Derivative liabilities, current	$—	$—	$—	$—	$250	$1,188
Derivative liabilities, non-current	$—	$—	$—	$—	$—	$—

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

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

Based on market prices at March 31, 2014, a $3.2 million loss would be realized, reported in pre-tax earnings, and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used for Electric Utility generation plants or those plants under power purchase agreements 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. Accordingly, the hedging activity is recognized in the Condensed Consolidated Statements of Income (Loss) or the Condensed Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

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, 2014		December 31, 2013		March 31, 2013	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	16,140,000	80	17,930,000	84	13,180,000	80
Natural gas options purchased	1,320,000	12	3,890,000	8	440,000	5
Natural gas basis swaps purchased	14,575,000	69	14,785,000	60	11,350,000	69

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, 2014	December 31, 2013	March 31, 2013
Derivative assets, current	$1,846	$662	$522
Derivative assets, non-current	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$4,420	$7,567	$4,315

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, 2014	December 31, 2013	March 31, 2013	
	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	De-designated Interest Rate Swaps [(c)]
Notional	$75,000	$75,000	$150,000	$250,000
Weighted average fixed interest rate	4.97 %	4.97 %	5.04 %	5.67 %
Maximum terms in years	2.75	3.00	3.75	0.75
Derivative liabilities, current	$3,498	$3,474	$6,982	$80,692
Derivative liabilities, non-current	$4,805	$5,614	$15,237	$—

(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 swaps.

(b) At March 31, 2013, $75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and $75 million were designated to borrowings on our project financing debt at Black Hills Wyoming. These swaps are priced using three-month LIBOR, matching the floating portion of the related debt. The portion of the swaps that were designated to Black Hills Wyoming were settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on March 31, 2014, market interest rates and balances related to our interest rate swaps, a loss of approximately $3.5 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, 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)		$—

Three Months Ended March 31, 2013

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	$(19)	Interest expense	$(1,796)		$—
Commodity derivatives	(2,759)	Revenue	1,092		—
Total	$(2,778)		$(704)		$—

(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 and 9 to the Consolidated Financial Statements included in our 2013 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.

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Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity option contracts for our Oil and Gas segment are valued using the market approach and can include calls and puts. Fair value was derived using quoted 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.

- The commodity basis swaps for our Oil and Gas segment are valued using the market approach with the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR. We utilize observable inputs which support a 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) and OTC basis swaps (Level 3) 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. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third-party market participant because these instruments are not traded on an exchange.

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, 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

	As of December 31, 2013				
	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	—	130	—	(75)	55
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	815	—	(815)	—
Commodity derivatives —Utilities	—	3,030	—	(2,368)	662
Total	$—	$3,975	$—	$(3,258)	$717
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	1,229	—	(1,229)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	531	—	(531)	—
Commodity derivatives — Utilities	—	9,100	—	(9,100)	—
Interest rate swaps	—	9,088	—	—	9,088
Total	$—	$19,948	$—	$(10,860)	$9,088

	As of March 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$71	$—	$(11)	$60
Basis Swaps -- Oil	—	836	—	(75)	761
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	435	—	(148)	287
Commodity derivatives — Utilities	—	1,897	—	(1,375)	522
Total	$—	$3,239	$—	$(1,609)	$1,630
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$396	$—	$(204)	$192
Basis Swaps -- Oil	—	670	—	(612)	58
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	3,216	—	(2,028)	1,188
Commodity derivatives — Utilities	—	5,862	—	(5,862)	—
Interest rate swaps	—	108,871	—	(5,960)	102,911
Total	$—	$119,015	$—	$(14,666)	$104,349

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, 2014, December 31, 2013, and March 31, 2013, 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, 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
Total derivatives not designated as hedges		$1,846	$5,539

As of December 31, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$248	$—
Commodity derivatives	Derivative assets — non-current	698	—
Commodity derivatives	Derivative liabilities — current	—	1,541
Commodity derivatives	Derivative liabilities — non-current	—	219
Interest rate swaps	Derivative liabilities — current	—	3,474
Interest rate swaps	Derivative liabilities — non-current	—	5,614
Total derivatives designated as hedges		$946	$10,848
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$662	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	6,732
Total derivatives not designated as hedges		$662	$6,732

As of March 31, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$832	$—
Commodity derivatives	Derivative assets — non-current	206	—
Commodity derivatives	Derivative liabilities — current	—	3,110
Commodity derivatives	Derivative liabilities — non-current	—	1,114
Interest rate swaps	Derivative liabilities — current	—	6,982
Interest rate swaps	Derivative liabilities — non-current	—	15,237
Total derivatives designated as hedges		$1,038	$26,443
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$2,201	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	58
Commodity derivatives	Derivative liabilities — non-current	—	5,862
Interest rate swaps	Derivative liabilities — current	—	86,652
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$2,201	$92,572

(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, 2014		December 31, 2013		March 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$17,641	$17,641	$7,841	$7,841	$12,397	$12,397
Restricted cash and equivalents [(a)]	$2	$2	$2	$2	$6,846	$6,846
Notes payable [(a)]	$100,000	$100,000	$82,500	$82,500	$245,000	$245,000
Long-term debt, including current maturities [(b)]	$1,396,949	$1,541,727	$1,396,948	$1,491,422	$1,041,114	$1,208,909

(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, 2014	March 31, 2013
Gains (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$894	$1,796
Commodity contracts	Revenue	311	(1,092)
		1,205	704
Income tax	Income tax benefit (expense)	(425)	(236)
Reclassification adjustments related to cash flow hedges, net of tax		$780	$468
Amortization of defined benefit plans:			
Prior service cost	Utilities - Operations and maintenance	$(25)	$(31)
	Non-regulated energy operations and maintenance	12	(32)
Actuarial gain (loss)	Utilities - Operations and maintenance	157	421
	Non-regulated energy operations and maintenance	85	274
		229	632
Income tax	Income tax benefit (expense)	(81)	(175)

Reclassification adjustments related to defined benefit plans, net of tax	$148	$457

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, 2012	$(15,713)	$(19,775)	$(35,488)
Other comprehensive income (loss), net of tax	(1,193)	457	(736)
Balance as of March 31, 2013	$(16,906)	$(19,318)	$(36,224)
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)

(12) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Supplemental disclosures of cash flow for the three months ended are as follows (in thousands):

	Three Months Ended	
	March 31, 2014	March 31, 2013
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$40,939	$31,780
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)	$(11,452)	$(12,768)
Income taxes, net	$4	$(4,656)

(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,	
	2014	2013
Service cost	$1,362	$1,608
Interest cost	3,963	3,825
Expected return on plan assets	(4,516)	(4,654)
Prior service cost	16	16
Net loss (gain)	1,201	3,062
Net periodic benefit cost	$2,026	$3,857

Non-pension Defined Benefit Postretirement Healthcare Plans

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

	Three Months Ended March 31,	
	2014	2013
Service cost	$425	$419
Interest cost	479	417
Expected return on plan assets	(21)	(20)
Prior service cost (benefit)	(107)	(125)
Net loss (gain)	40	121
Net periodic benefit cost	$816	$812

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,	
	2014	2013
Service cost	$374	$348
Interest cost	362	332
Prior service cost	1	1
Net loss (gain)	124	198
Net periodic benefit cost	$861	$879

Contributions

We anticipate that we will make contributions to the benefit plans during 2014 and 2015. 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, 2014	Additional Contributions Anticipated for 2014	Contributions Anticipated for 2015
Defined Benefit Pension Plans	$—	$—	$2,806
Non-pension Defined Benefit Postretirement Healthcare Plans	$956	$2,868	$3,822
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$373	$1,118	$1,494

(14) COMMITMENTS AND CONTINGENCIES

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 2013 Annual Report on Form 10-K except for those described below.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to satisfy our delivery commitments under this agreement.

Other Commitments

Construction of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by September 30, 2014. As of March 31, 2014, committed contracts for equipment purchases and for construction were 100% and 83% complete, respectively.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A state fire investigator 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 lawsuit was filed in the United States District Court for the District of Wyoming, which forty-seven plaintiffs have now joined, asserting claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance, and trespass. Although not currently included in the lawsuit, Black Hills Power also received written damage claims from an additional landowner and from the State of Wyoming. Altogether the claims seek 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, for a current total amount of $16 million. In addition to claims for these compensatory damages, the lawsuit seeks recovery of punitive damages. Our investigation of the cause and origin of the fire is ongoing. We have denied and will vigorously defend all claims arising out of the fire, pending the completion of our investigation. We cannot predict the outcome of our 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. In order to limit our exposure to losses due to civil liability claims, and related litigation expense, we maintain insurance coverage above a $1.0 million deductible. We expect this coverage to limit our exposure, and we will pursue recoveries to the maximum extent available under the policies. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, as of March 31, 2014, 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. However, we cannot reasonably estimate the amount of such possible loss because our investigation is ongoing, damage claims are currently incomplete or undocumented, and there are significant factual and legal issues to be resolved. Further claims may be presented by these and other parties. 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, 2014, we were in compliance with these 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, 2014:

- 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, 2014, the restricted net assets at our Utilities Group were approximately $94 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 203,500 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 35,500 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 538,000 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, 2014 and 2013, and our financial condition as of March 31, 2014, December 31, 2013 and March 31, 2013, 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 55.

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, 2014 Compared to Three Months Ended March 31, 2013. Net income (loss) for the three months ended March 31, 2014 was $48 million, or $1.08 per share, compared to Net income (loss) of $43 million, or $0.97 per share, reported for the same period in 2013.

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

	Three Months Ended March 31,		
	2014	2013	Variance
Revenue			
Utilities	$441,439	$362,442	$78,997
Non-regulated Energy	52,696	49,287	3,409
Inter-company eliminations	(33,966)	(31,058)	(2,908)
	$460,169	$380,671	$79,498
Net income (loss)			
Electric Utilities	$14,575	$12,356	$2,219
Gas Utilities	24,698	18,483	6,215
Utilities	39,273	30,839	8,434
Power Generation	8,073	5,644	2,429
Coal Mining	2,464	1,065	1,399
Oil and Gas	(2,022)	(53)	(1,969)
Non-regulated Energy	8,515	6,656	1,859
Corporate activities and eliminations [(a)]	330	5,702	(5,372)
Net income (loss)	$48,118	$43,197	$4,921

(a) Corporate activities for the three months ended March 31, 2013 include a $4.8 million net after-tax non-cash mark-to-market gain on certain interest rate swaps. These same interest rate swaps were settled in November 2013.

Overview of Business Segments and Corporate Activity

Utilities Group

- Gas Utilities quarter-to-date results were favorably impacted by colder weather during 2014. Heating degree days were 7% higher for the three months ended March 31, 2014, compared to the same period in 2013. Heating degree days for the three months ended March 31, 2014 were 14% higher than normal, compared to 6% higher than normal for the same period in 2013.

- Construction continued on Cheyenne Prairie, a natural gas-fired electric generating facility to serve Cheyenne Light and Black Hills Power customers. The 132 MW generation project is expected to cost approximately $222 million, exclusive of construction financing costs which will be recovered through the construction financing riders. The Electric Utilities recorded additional gross margins of approximately $3.3 million for the three months ended March 31, 2014, relating to these riders. Project to date; we have expended approximately $183 million. The project is on schedule to be placed into service in October 2014.

- On April 30, 2014, Colorado Electric filed a rate request with the CPUC for an annual revenue increase of $8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to recover a return on the expenditures associated with the construction of the new generating unit approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of 50.5% equity and 49.5% debt.

- On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue by $7.3 million primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

- On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt.

- On March 21, 2014, Black Hills Power retired the Ben French, Neil Simpson I, and Osage coal-fired power plants. These three plants totaling 81 MW were closed because of federal environmental regulations. These plants will largely be replaced by Black Hills Power’s share of the Cheyenne Prairie Generating Station.

- On February 25, 2014, the CPUC issued a final order after rehearing, approving a CPCN for the retirement of Pueblo Unit #5 and #6, effective December 31, 2013.

- On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of $2.8 million, to recover investments made in electric infrastructure, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt.

- Our Utilities Group continued its efforts to acquire small municipal gas distribution systems adjacent to our existing service territories. During 2014, we acquired an additional gas system, adding approximately 70 customers, and announced the pending acquisition of assets serving approximately 400 customers.

Non-regulated Energy Group

- Oil and Gas reported a 3% reduction in total volumes sold for the three months ended March 31, 2014. Oil and Gas results benefited from a 1% increase in average hedged price received for crude oil during the three months ended March 31, 2014, compared to the same period in 2013, and a 13% increase in average hedged price received for natural gas for the same period.

- On March 6, 2014, the new Summit Midstream cryogenic gas processing plant with a capacity of 20,000 Mcf per day started serving the company's gas production in the southern Piceance Basin.

- Two horizontal wells were drilled and completed in the Mancos Shale formation in 2013. Production from these two wells during the quarter was constrained by processing capacity until the new cryogenic gas processing plant began operations in March.

Corporate Activities

- On January 30, 2014, Moody's raised our corporate credit rating to Baa1 from Baa2 with continued stable outlook.

- Consolidated interest expense decreased by approximately $5.8 million for the three months ended March 31, 2014, compared to the three months ended March 31, 2013, due primarily to the refinancing activities occurring during the fourth quarter of 2013.

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 electric operations of Black Hills Power, Colorado Electric and the 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 gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of 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,		
	2014	2013	Variance
	(in thousands)		
Revenue — electric	$168,365	$150,373	$17,992
Revenue — gas	13,737	12,257	1,480
Total revenue	182,102	162,630	19,472
Fuel, purchased power and cost of gas — electric	78,418	65,689	12,729
Purchased gas — gas	8,274	6,438	1,836
Total fuel, purchased power and cost of gas	86,692	72,127	14,565
Gross margin — electric	89,947	84,684	5,263
Gross margin — gas	5,463	5,819	(356)
Total gross margin	95,410	90,503	4,907
Operations and maintenance	42,601	38,835	3,766
Depreciation and amortization	19,086	19,161	(75)
Total operating expenses	61,687	57,996	3,691
Operating income	33,723	32,507	1,216
Interest expense, net	(12,013)	(14,397)	2,384
Other income (expense), net	256	285	(29)
Income tax benefit (expense)	(7,391)	(6,039)	(1,352)
Net income (loss)	$14,575	$12,356	$2,219

	Three Months Ended March 31,	
Revenue - Electric (in thousands)	2014	2013
Residential:		
Black Hills Power	$20,061	$16,442
Cheyenne Light	9,673	9,330
Colorado Electric	24,679	24,121
Total Residential	54,413	49,893
Commercial:		
Black Hills Power	21,528	17,484
Cheyenne Light	14,394	12,767
Colorado Electric	21,890	21,151
Total Commercial	57,812	51,402
Industrial:		
Black Hills Power	7,335	6,010
Cheyenne Light	7,224	4,855
Colorado Electric	9,038	9,637
Total Industrial	23,597	20,502
Municipal:		
Black Hills Power	792	714
Cheyenne Light	454	458
Colorado Electric	3,307	2,547
Total Municipal	4,553	3,719
Total Retail Revenue - Electric	140,375	125,516
Contract Wholesale:		
Total Contract Wholesale - Black Hills Power	5,598	5,767
Off-system Wholesale:		
Black Hills Power	9,075	6,250
Cheyenne Light	2,387	2,682
Colorado Electric	2,082	1,107
Total Off-system Wholesale	13,544	10,039
Other Revenue:		
Black Hills Power	6,878	7,150
Cheyenne Light	753	566
Colorado Electric	1,217	1,335
Total Other Revenue	8,848	9,051
Total Revenue - Electric	$168,365	$150,373

Quantities Generated and Purchased (in MWh)	Three Months Ended March 31, 2014	2013
Generated —		
Coal-fired:		
Black Hills Power [(a)]	417,248	427,015
Cheyenne Light	169,789	172,312
Total Coal-fired	587,037	599,327
Natural Gas and Oil:		
Black Hills Power	2,308	3,120
Colorado Electric [(b)]	18,068	31,054
Total Natural Gas and Oil	20,376	34,174
Wind:		
Colorado Electric	14,329	11,173
Total Wind	14,329	11,173
Total Generated:		
Black Hills Power	419,556	430,135
Cheyenne Light	169,789	172,312
Colorado Electric	32,397	42,227
Total Generated	621,742	644,674
Purchased —		
Black Hills Power	430,801	388,199
Cheyenne Light	207,318	201,845
Colorado Electric	470,101	455,138
Total Purchased	1,108,220	1,045,182
Total Generated and Purchased:		
Black Hills Power	850,357	818,334
Cheyenne Light	377,107	374,157
Colorado Electric	502,498	497,365
Total Generated and Purchased	1,729,962	1,689,856

(a) Decrease reflects the retirement of Neil Simpson I on March 21, 2014.

(b) Decrease reflects an unplanned outage due to a turbine bearing replacement and combustor upgrade at Pueblo Airport Generation Station.

	Three Months Ended March 31,	
Quantity (in MWh)	2014	2013
Residential:		
Black Hills Power	171,311	160,970
Cheyenne Light	70,656	75,456
Colorado Electric	153,632	155,436
Total Residential	395,599	391,862
Commercial:		
Black Hills Power	184,448	175,617
Cheyenne Light	126,412	129,429
Colorado Electric	158,179	170,705
Total Commercial	469,039	475,751
Industrial:		
Black Hills Power	100,851	91,632
Cheyenne Light	90,724	69,952
Colorado Electric	90,116	78,549
Total Industrial	281,691	240,133
Municipal:		
Black Hills Power	7,686	7,783
Cheyenne Light	2,493	2,595
Colorado Electric	26,687	18,046
Total Municipal	36,866	28,424
Total Retail Quantity Sold	1,183,195	1,136,170
Contract Wholesale:		
Total Contract Wholesale - Black Hills Power	95,228	103,784
Off-system Wholesale:		
Black Hills Power	254,796	238,447
Cheyenne Light	52,356	70,308
Colorado Electric	30,746	31,777
Total Off-system Wholesale	337,898	340,532
Total Quantity Sold:		
Black Hills Power	814,320	778,233
Cheyenne Light	342,641	347,740
Colorado Electric	459,360	454,513
Total Quantity Sold	1,616,321	1,580,486
Other Uses, Losses or Generation, net [a]:		
Black Hills Power	36,037	40,101
Cheyenne Light	34,466	26,417
Colorado Electric	43,138	42,852
Total Other Uses, Losses and Generation, net	113,641	109,370

Total Energy	1,729,962	1,689,856

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(a) Includes company uses, line losses, test energy and excess exchange production.

Degree Days	Three Months Ended March 31, 2014		2013	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:				
Black Hills Power	3,410	6 %	3,210	— %
Cheyenne Light	3,206	6 %	3,162	5 %
Colorado Electric	2,670	2 %	2,750	5 %
Combined	3,028	5 %	2,986	3 %

Electric Utilities Power Plant Availability	Three Months Ended March 31, 2014	2013
Coal-fired plants	95.5 %	96.9 %
Other plants [(a)]	78.1 %	98.6 %
Total availability	86.6 %	97.8 %

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(a) 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, 2014	2013
Revenue - Gas (in thousands):		
Residential	$8,224	$7,532
Commercial	3,977	3,608
Industrial	1,285	898
Other Sales Revenue	251	219
Total Revenue - Gas	$13,737	$12,257
Gross Margin (in thousands):		
Residential	$3,605	$3,960
Commercial	1,332	1,492
Industrial	275	148
Other Gross Margin	251	219
Total Gross Margin	$5,463	$5,819
Volumes Sold (Dth):		
Residential	1,035,177	1,093,000
Commercial	564,394	625,937
Industrial	255,927	226,947
Total Volumes Sold	1,855,498	1,945,884

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013: Net income for the Electric Utilities was $14.6 million for the three months ended March 31, 2014, compared to $12.4 million for the three months ended March 31, 2013, as a result of:

Gross margin increased primarily due to $2.0 million on increased electric retail megawatt hours sold, and a return on additional investments which increased base electric margins by $3.0 million and increased rider margins by $3.3 million. These increases are partially offset by a charge to gross margin of $0.4 million reflecting a power cost sharing mechanism in place at Cheyenne Light, a $0.4 million decrease from wholesale quantities sold, a $0.9 million decrease from contract pricing for industrial customers, and a $1.9 million decrease resulting from energy cost adjustments.

Operations and maintenance increased primarily due to an increase in employee costs and property taxes.

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

Interest expense, net decreased primarily due to a refinancing higher cost debt refinanced in the fourth quarter of 2013.

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 2014 primarily due to the research and development tax credit not being extended to 2014. The first quarter of 2013 reflected the entire year of the 2012 research and development tax credit due to retroactive reinstatement in January 2013 by Congress of the credit.

Gas Utilities

	Three Months Ended March 31,		
	2014	2013	Variance
	(in thousands)		
Natural gas — regulated	$251,232	$191,951	$59,281
Other — non-regulated services	8,105	7,861	244
Total revenue	259,337	199,812	59,525
Natural gas — regulated	170,774	120,380	50,394
Other — non-regulated services	3,722	3,717	5
Total cost of sales	174,496	124,097	50,399
Gross margin	84,841	75,715	9,126
Operations and maintenance	35,378	33,226	2,152
Depreciation and amortization	6,521	6,503	18
Total operating expenses	41,899	39,729	2,170
Operating income (loss)	42,942	35,986	6,956
Interest expense, net	(3,853)	(6,277)	2,424
Other income (expense), net	(17)	12	(29)
Income tax benefit (expense)	(14,374)	(11,238)	(3,136)
Net income (loss)	$24,698	$18,483	$6,215

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Revenue (in thousands)	Three Months Ended March 31, 2014	2013
Residential:		
Colorado	$23,687	$19,794
Nebraska	62,892	48,852
Iowa	54,764	38,751
Kansas	33,277	25,765
Total Residential	174,620	133,162
Commercial:		
Colorado	4,697	3,660
Nebraska	20,066	16,247
Iowa	25,914	17,775
Kansas	11,671	8,789
Total Commercial	62,348	46,471
Industrial:		
Colorado	77	48
Nebraska	208	205
Iowa	1,172	745
Kansas	1,086	932
Total Industrial	2,543	1,930
Transportation:		
Colorado	325	401
Nebraska	5,730	4,716
Iowa	1,761	1,539
Kansas	2,493	2,049
Total Transportation	10,309	8,705
Other Sales Revenue:		
Colorado	31	(74)
Nebraska	703	614
Iowa	152	112
Kansas	526	1,031
Total Other Sales Revenue	1,412	1,683
Total Regulated Revenue	251,232	191,951
Non-regulated Services	8,105	7,861
Total Revenue	$259,337	$199,812

	Three Months Ended March 31,	
Gross Margin (in thousands)	2014	2013
Residential:		
Colorado	$6,372	$6,238
Nebraska	20,889	18,311
Iowa	15,210	13,589
Kansas	11,584	10,204
Total Residential	54,055	48,342
Commercial:		
Colorado	1,060	989
Nebraska	5,163	4,635
Iowa	5,225	4,452
Kansas	3,183	2,644
Total Commercial	14,631	12,720
Industrial:		
Colorado	30	30
Nebraska	68	54
Iowa	85	82
Kansas	236	224
Total Industrial	419	390
Transportation:		
Colorado	326	401
Nebraska	5,731	4,716
Iowa	1,761	1,539
Kansas	2,493	2,049
Total Transportation	10,311	8,705
Other Sales Margins:		
Colorado	31	(74)
Nebraska	702	614
Iowa	152	112
Kansas	157	761
Total Other Sales Margins	1,042	1,413
Total Regulated Gross Margin	80,458	71,570
Non-regulated Services	4,383	4,145
Total Gross Margin	$84,841	$75,715

Distribution Quantities Sold and Transportation (in Dth)	Three Months Ended March 31, 2014	2013
Residential:		
Colorado	3,021,434	2,921,335
Nebraska	6,986,293	5,737,673
Iowa	6,643,044	5,290,366
Kansas	3,881,555	3,216,306
Total Residential	20,532,326	17,165,680
Commercial:		
Colorado	635,690	576,276
Nebraska	2,475,156	2,198,798
Iowa	3,485,692	2,805,673
Kansas	1,541,967	1,277,134
Total Commercial	8,138,505	6,857,881
Industrial:		
Colorado	10,325	9,737
Nebraska	26,965	30,680
Iowa	193,863	142,324
Kansas	180,087	188,821
Total Industrial	411,240	371,562
Wholesale and Other:		
Kansas	68,633	55,010
Total Wholesale and Other	68,633	55,010
Total Distribution Quantities Sold	29,150,704	24,450,133
Transportation:		
Colorado	330,344	412,709
Nebraska	9,963,219	8,682,315
Iowa	6,157,366	5,679,157
Kansas	4,827,137	4,052,018
Total Transportation	21,278,066	18,826,199
Total Distribution Quantities Sold and Transportation	50,428,770	43,276,332

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Over 70 percent 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,					
	2014			2013		
Heating Degree Days:	Actual	Variance From 30-Year Average		Actual	Variance From 30-Year Average	
Colorado	2,859	2	%	2,872	3	%
Nebraska	3,272	7	%	3,129	3	%
Iowa	4,174	19	%	3,743	11	%
Kansas [(a)]	2,689	8	%	2,550	3	%
Combined [(b)]	3,524	14	%	3,306	6	%

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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, 2014 Compared to the Three Months Ended March 31, 2013: Net income for the Gas Utilities was $24.7 million for the three months ended March 31, 2014, compared to Net income of $18.5 million for the three months ended March 31, 2013, as a result of:

Gross margin increased primarily due to colder weather than the same period in the prior year resulting in higher residential, commercial, and transport volumes sold. Heating degree days were 7% higher for the three months ended March 31, 2014, compared to the same period in the prior year and 14% higher than normal.

Operations and maintenance increased primarily due to an increase in employee costs and property taxes.

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

Interest expense, net decreased primarily due to refinancing higher cost debt in the fourth quarter of 2013.

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

Income tax benefit (expense): The effective tax rate for 2014 was slightly lower than 2013 due primarily to an increase in an estimated flow-through tax adjustment.

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
Cheyenne Light [(a)]	Electric/Gas	12/2013	pending	$14.1	pending
Black Hills Power [(b)]	Electric	1/2014	pending	$2.8	pending
Black Hills Power [(c)]	Electric	3/2014	pending	$14.6	pending
Iowa Gas [(d)]	Gas	2/2014	4/2014	$0.5	$0.5
Kansas Gas [(e)]	Gas	4/2014	pending	$7.3	pending
Colorado Electric [(f)]	Electric	4/2014	pending	$8.0	pending

(a) On December 2, 2013, Cheyenne Light filed a rate request with the WPSC for annual electric and natural gas revenue increases of $12.8 million and $1.3 million, respectively to recover investment in Cheyenne Prairie, existing infrastructure and increased operating costs. The filing seeks a return on equity of 10.25% and a capital structure of 54.0% equity and 46.0% debt. Cheyenne Light is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service date.

(b) On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of $2.8 million, to recover investments made in electric infrastructure, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt. Black Hills Power is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service date.

(c) On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt. Black Hills Power is seeking to implement the new rates on October 1, 2014, to coincide with Cheyenne Prairie's expected in-service date.

(d) On April 15, 2014, the IUB approved a capital investment recovery surcharge increase of $0.5 million.

(e) On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue by $7.3 million primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

(f) On April 30, 2014, Colorado Electric filed a rate request with the CPUC for an annual revenue increase of $8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to recover a return on the expenditures associated with the construction of the new generating unit approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of 50.5% equity and 49.5% debt.

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,		
	2014	2013	Variance
	(in thousands)		
Revenue	$22,348	$20,360	$1,988
Operations and maintenance	7,677	7,791	(114)
Depreciation and amortization	1,209	1,226	(17)
Total operating expense	8,886	9,017	(131)
Operating income	13,462	11,343	2,119
Interest expense, net	(928)	(2,674)	1,746
Other (expense) income, net	(9)	1	(10)
Income tax (expense) benefit	(4,452)	(3,026)	(1,426)
Net income (loss)	$8,073	$5,644	$2,429

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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,	
	2014	2013
Quantities Sold, Generated and Purchased (MWh)	(in thousands)	
Sold		
Black Hills Colorado IPP	285,956	234,196
Black Hills Wyoming	140,608	142,106
Total Sold	426,564	376,302
Generated		
Black Hills Colorado IPP	285,956	234,196
Black Hills Wyoming	140,678	144,189
Total Generated	426,634	378,385
Purchased		
Black Hills Colorado IPP	—	—
Black Hills Wyoming	989	—
Total Purchased	989	—

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

	Three Months Ended March 31,	
	2014	2013
Contracted power plant fleet availability:		

Coal-fired plant	99.3	%	100.0	%
Natural gas-fired plants	97.9	%	98.6	%
Total availability	98.2	%	98.9	%

Results of Operations for Power Generation for the Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013: Net income for the Power Generation segment was $8.1 million for the three months ended March 31, 2014, compared to Net income of $5.6 million for the same period in 2013 as a result of:

Revenue increased primarily due to an increase in prices on delivered megawatt hours.

Operations and maintenance was comparable to the same period in the prior year.

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

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013.

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

Income tax (expense) benefit: The effective tax rate in 2013 was favorably impacted by a state tax adjustment.

Coal Mining

	Three Months Ended March 31,		
	2014	2013	Variance
	(in thousands)		
Revenue	$15,498	$13,583	$1,915
Operations and maintenance	10,131	10,151	(20)
Depreciation, depletion and amortization	2,690	2,865	(175)
Total operating expenses	12,821	13,016	(195)
Operating income (loss)	2,677	567	2,110
Interest (expense) income, net	(103)	(131)	28
Other income, net	603	613	(10)
Income tax benefit (expense)	(713)	16	(729)
Net income (loss)	$2,464	$1,065	$1,399

The following table provides certain operating statistics for our Coal Mining segment (in thousands):

	Three Months Ended March 31,	
	2014	2013
Tons of coal sold	1,087	1,053
Cubic yards of overburden moved	910	1,059

Results of Operations for Coal Mining for the Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013: Net income for the Coal Mining segment was $2.5 million for the three months ended March 31, 2014, compared to Net income of $1.1 million for the same period in 2013 as a result of:

Revenue increased primarily due to an 11% increase in price per ton sold and a 3% increase in tons sold. 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 was comparable to prior year, reflecting a lower stripping ratio that drove a decline in overburden removal costs, and a favorable coal tax adjustment of $0.7 million, partially offset by an increase in repairs and maintenance.

Depreciation, depletion and amortization were comparable to the same period in the prior year.

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

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

Income tax benefit (expense): The increase in the effective tax rate in 2014 is due primarily to the reduced impact of the tax benefit of percentage depletion.

Oil and Gas

	Three Months Ended March 31,		
	2014	2013	Variance
	(in thousands)		
Revenue	$14,850	$15,344	$(494)
Operations and maintenance	11,139	10,255	884
Depreciation, depletion and amortization	6,633	5,367	1,266
Total operating expenses	17,772	15,622	2,150
Operating income (loss)	(2,922)	(278)	(2,644)
Interest income (expense), net	(455)	79	(534)
Other income (expense), net	38	(77)	115
Income tax benefit (expense)	1,317	223	1,094
Net income (loss)	$(2,022)	$(53)	$(1,969)

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

	Three Months Ended March 31,	
	2014	2013
Production:		
Bbls of oil sold	74,262	96,803
Mcf of natural gas sold	1,759,964	1,732,950
Gallons of NGL sold	1,135,721	945,814
Mcf equivalent sales	2,367,782	2,448,884

	Three Months Ended March 31,	
	2014	2013
Average price received: [(a)]		
Oil/Bbl	$90.75	$89.73
Gas/Mcf	$3.35	$2.96
NGL/gallon	$1.17	$0.94
Depletion expense/Mcfe	$2.25	$1.78

(a) Net of hedge settlement gains and losses.

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

	Three Months Ended March 31, 2014				Three Months Ended March 31, 2013			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.54	$0.43	$0.63	$2.60	$1.29	$0.34	$0.42	$2.05
Piceance	(0.06)	0.24	0.57	0.75	0.65	0.65	0.33	1.63
Powder River	2.36	—	1.34	3.70	1.26	—	1.24	2.50
Williston	0.67	—	1.90	2.57	0.83	—	1.07	1.90
All other properties	1.61	—	0.02	1.63	0.70	—	0.38	1.08
Total weighted average	$1.19	$0.23	$0.74	$2.16	$1.08	$0.23	$0.65	$1.96

Results of Operations for Oil and Gas for the Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013: Net loss for the Oil and Gas segment was $2.0 million for the three months ended March 31, 2014, compared to Net loss of $0.1 million for the same period in 2013 as a result of:

Revenue decreased primarily due to a 3% decrease in production primarily driven by normal declines on non-operated crude oil volumes sold, partially offset by a 13% increase in the average hedged price received for natural gas sold, and a 1% increase in the average price received for crude oil sold.

Operations and maintenance increased primarily due to higher non-operated well costs, higher production taxes and ad valorem taxes on higher natural gas revenue.

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

Interest income (expense), net was comparable to prior year.

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

Income tax (expense) benefit: Each period presented reflects a tax benefit that was favorably impacted by the tax effect of essentially the same amount of estimated percentage depletion deduction.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended March 31, 2014 Compared to the Three Months Ended March 31, 2013: Net income for Corporate was $0.3 million for the three months ended March 31, 2014, compared to Net income of $5.7 million for the three months ended March 31, 2013 as a result of:

- The settlement of the de-designated interest rate swaps in the fourth quarter of 2013, resulted in no activity for the three months ended March 31, 2014, compared to the recognition of an unrealized, non-cash mark-to-market gain of $7.5 million during the three months ended March 31, 2013.

- The income for the three months ended March 31, 2014 included lower interest expense as compared to the three months ended March 31, 2013, as a result of lower interest rate debt from refinancing activities in fourth quarter 2013 and the settlement of the de-designated interest rate swaps.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2013 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 2013 Annual Report on Form 10-K.

Liquidity and Capital Resources

OVERVIEW

BHC and its subsidiaries require 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 items impacting cash are our capital expenditures, the purchase of natural gas for our Utilities Group and our Power Generation segment, and the payment of dividends to our shareholders. We could 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, 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.

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Cash Flow Activities

The following table summarizes our cash flows for the three months ended March 31, 2014 and 2013 (in thousands):

Cash provided by (used in):	2014	2013	Increase (Decrease)
Operating activities	$98,098	$109,232	$(11,134)
Investing activities	$(86,829)	$(62,909)	$(23,920)
Financing activities	$(1,469)	$(49,388)	$47,919

Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013

Operating Activities

Net cash provided by operating activities was $11 million lower for the three months ended March 31, 2014, than for the same period in 2013 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $15 million higher for the three months ended March 31, 2014 than for the same period in the prior year.

- Net outflows from operating assets and liabilities were $27 million for the three months ended March 31, 2014, compared to net cash outflows of $0.4 million in the same period in the prior year. Changes are primarily due to:

- Increased working capital requirements resulting from higher natural gas volumes sold driven by cold weather and higher natural gas prices creating an increase in GCAs recorded in regulatory assets in our Utility Group, and

- Receipt in 2013 of approximately $8.0 million from a government grant relating to the Busch Ranch wind project.

Investing Activities

Net cash used in investing activities was $87 million for the three months ended March 31, 2014, compared to net cash used in investing activities of $63 million for the same period in 2013 for a variance of $24 million. The variance was primarily driven by:

- Capital expenditures of approximately $83 million for the three months ended March 31, 2014, compared to $64 million for the three months ended March 31, 2013. The increase is related primarily to the construction of Cheyenne Prairie at our Electric Utilities segment and capital expenditures at our Oil and Gas segment.

Financing Activities

Net cash used in financing activities for the three months ended March 31, 2014, was $1.5 million, compared to net cash used in financing activities for the same period in 2013 of $49 million for a variance of $48 million. The variance was primarily driven by:

- Net short-term borrowings increased primarily due to capital expenditures and working capital requirements resulting from colder weather.

Dividends

Dividends paid on our common stock totaled $17.4 million for the three months ended March 31, 2014, or $0.39 per share. On April 28, 2014, our board of directors declared a quarterly dividend of $0.39 per share payable June 1, 2014, which is equivalent to an annual dividend rate of $1.56 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

We have a $500 million corporate Revolving Credit Facility that matures on February 1, 2017, which has 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 are 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 the lowest credit ratings of S&P and Moody’s that apply to our debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.375%, 1.375% and 1.375%, respectively, during the three months ended March 31, 2014. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.20% 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, 2014	Letters of Credit at March 31, 2014	Available Capacity at March 31, 2014
Revolving Credit Facility	February 1, 2017	$500	$100	$28	$372

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 the ratio of our recourse debt, letters of credit and certain guarantees issued, divided 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, 2014.

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 2.75 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 $8.3 million at March 31, 2014.

Financing Activities

On November 19, 2013, we entered into a $525 million, 4.25% senior unsecured note expiring on November 30, 2023. The proceeds of this debt were used to:

- Redeem our $250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest.

- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of $87 million originally due on December 9, 2016, and settle the interest rate swaps designated to this project financing of $8.5 million.

- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million.

- Pay down $55 million of the Revolving Credit Facility.

- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new two-year $275 million term loan expiring on June 19, 2015. The proceeds from this new term loan repaid the $150 million term loan due on June 24, 2013, the $100 million long-term corporate term loan due on September 30, 2013, and $25 million in short-term borrowing under our Revolving Credit Facility. At March 31, 2014, the cost of borrowing under this new term loan was 1.3125% (LIBOR plus a margin of 1.125%).

Future Financing Plans

We are considering the following financing activities:

- Evaluation of long-term debt financing options, including the issuance of utility first mortgage bonds using a private placement delayed draw feature to primarily finance the Cheyenne Prairie capital project. The draw is anticipated to occur in the second or third quarter prior to the in-service date of Cheyenne Prairie; and

- Extension of our Revolving Credit Facility which expires in 2017.

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 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, 2014, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $94 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, 2014, 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 2013 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, our credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and our credit ratings, management believes that we will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. Credit ratings are prepared by third party rating agencies and 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, 2014:

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

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(a) On January 30, 2014, Moody's upgraded the BHC credit rating to Baa1 with a Stable outlook.

The following table represents the credit ratings of Black Hills Power's Senior Secured Mortgage Bonds at March 31, 2014:

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

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* On January 30, 2014, Moody's upgraded the BHP credit rating to A1 from A2.

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Capital Requirements

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

	Expenditures for the Three Months Ended March 31, 2014 [(a)]	Total 2014 Planned Expenditures [(b)]	Total 2015 Planned Expenditures	Total 2016 Planned Expenditures
Utilities:				
Electric Utilities	$49,546	$250,700	$189,300	$160,500
Gas Utilities	6,323	63,000	62,000	47,600
Non-regulated Energy:				
Power Generation	708	2,500	5,200	3,200
Coal Mining	424	6,600	6,200	7,300
Oil and Gas	5,701	117,800	122,700	122,200
Corporate	2,034	8,700	5,900	6,100
	$64,736	$449,300	$391,300	$346,900

(a) Expenditures for the three months ended March 31, 2014 include the impact of accruals for property, plant and equipment.
(b) Includes actual expenditures for the three months ended March 31, 2014.

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

Except as noted below, 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 2013 Annual Report on Form 10-K.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to satisfy our delivery commitments under this agreement.

Construction Commitments

Construction of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by September 30, 2014. As of March 31, 2014, contracts for equipment purchases and for construction were 100% and 83% committed, respectively.

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 2013 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2013 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 statements.

FORWARD-LOOKING INFORMATION

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

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2013 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2013 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, 2014	December 31, 2013	March 31, 2013
Net derivative (liabilities) assets	$(3,693)	$(6,071)	$(3,965)
Cash collateral offset in Derivatives	5,539	6,733	4,487
Cash Collateral included in Other current assets	1,917	3,390	3,295
Net receivable (liability) position	$3,763	$4,052	$3,817

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2014, 2015 and 2016 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at March 31, 2014, were as follows:

Natural Gas

	March 31,	June 30,	September 30,	December 31,	Total Year
2014					
Swaps - MMBtu	—	1,282,500	1,215,000	1,185,000	3,682,500
Weighted Average Price per MMBtu	$—	$3.83	$3.98	$3.99	$3.93
2015					
Swaps - MMBtu	990,000	952,500	725,000	770,000	3,437,500
Weighted Average Price per MMBtu	$4.23	$3.99	$3.94	$4.00	$4.05
2016					
Swaps - MMBtu	313,750	300,000	292,500	270,000	1,176,250
Weighted Average Price per MMBtu	$3.77	$3.93	$4.11	$3.75	$3.89

Crude Oil

	March 31,	June 30,	September 30,	December 31,	Total Year
2014					
Swaps - Bbls	—	60,000	57,000	57,000	174,000
Weighted Average Price per Bbl	$—	$90.65	$90.55	$90.66	$90.62
Puts - Bbls	—	—	—	—	—
Weighted Average Price per Bbl	$—	$—	$—	$—	$—
Calls - Bbls	—	—	—	—	—
Weighted Average Price per Bbl	$—	$—	$—	$—	$—
2015					
Swaps - Bbls	55,500	51,000	39,000	33,000	178,500
Weighted Average Price per Bbl	$89.98	$87.84	$87.73	$87.36	$88.39
2016					
Swaps - Bbls	24,000	24,000	21,000	21,000	90,000
Weighted Average Price per Bbl	$81.99	$81.99	$81.61	$81.61	$81.81
Puts - Bbls	—	—	—	—	—
Weighted Average Price per Bbl	$—	$—	$—	$—	$—
Calls - Bbls	—	—	—	—	—
Weighted Average Price per Bbl	$—	$—	$—	$—	$—

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 2013 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, 2014	December 31, 2013	March 31, 2013	
	Designated Interest Rate Swaps [a]	Designated Interest Rate Swaps [a]	Designated Interest Rate Swaps [b]	De-designated Interest Rate Swaps [c]
Notional	$75,000	$75,000	$150,000	$ 250,000
Weighted average fixed interest rate	4.97 %	4.97 %	5.04 %	5.67 %
Maximum terms in years	2.75	3.00	3.75	0.75
Derivative liabilities, current	$3,498	$3,474	$6,982	$ 80,692
Derivative liabilities, non-current	$4,805	$5,614	$15,237	$ —

(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 swaps.

(b) At March 31, 2013, $75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and $75 million were designated to borrowings on our project financing debt at Black Hills Wyoming. These swaps are priced using three-month LIBOR, matching the floating portion of the related swaps. The portion of the swaps that were designated to Black Hills Wyoming were settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on March 31, 2014 market interest rates and balances related to our interest rate swaps, a loss of approximately $3.5 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, 2014. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended March 31, 2014, 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.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2013 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 2013 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 quarter.

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)).
Exhibit 4.3*	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 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.

Exhibit 101 Financial Statements for XBRL Format.

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

SIGNATURES

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

BLACK HILLS CORPORATION

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

/s/ Anthony S. Cleberg
Anthony S. Cleberg, Executive Vice President and
Chief Financial Officer

Dated: May 2, 2014

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