BLACK HILLS CORP /SD/
Form 10-Q
May 03, 2013

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, 2013
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota   IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number (605) 721-1700

Former name, former address, and former fiscal year if changed since last report
NONE

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

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

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

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

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

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

Class	Outstanding at April 30, 2013	
Common stock, $1.00 par value	44,442,886	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
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
BHC	Black Hills Corporation; the Company
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Electric Generation	Black Hills Electric Generation, LLC, representing our Power Generation segment, 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
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, Wyo. 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 Gas	Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
Cooling degree day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
Conflict Mineral	As defined by the Dodd-Frank, conflict minerals are cassiterite, columbite-tantalite, gold and wolframite that are mined in the Democratic Republic of the Congo or surrounding countries
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

	were subsequently de-designated
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
Enserco	Enserco Energy Inc., representing our Energy Marketing segment, sold Feb. 29, 2012
FASB	Financial Accounting Standards Board

FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
IFRS	International Financial Reporting Standards
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent power producer
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent. Natural gas liquid is converted by dividing gallons by 7. Crude oil is converted by multiplying barrels by 6.
MMBtu	Million British thermal units
Moody’s	Moody’s Investors Service, Inc.
MWh	Megawatt-hour
NGL	Natural Gas Liquids. One gallon equals 7 Mcfe
OTC	Over-the-counter
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado
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
(unaudited)

	Three Months Ended March 31,	
	2013	2012
	(in thousands, except per share amounts)	
Revenue	$380,671	$365,851
Operating expenses:		
Utilities -		
Fuel, purchased power and cost of gas sold	168,173	157,183
Operations and maintenance	65,690	64,760
Non-regulated energy operations and maintenance	21,329	22,595
Depreciation, depletion and amortization	34,781	38,559
Taxes - property, production and severance	10,380	11,510
Other operating expenses	472	1,196
Total operating expenses	300,825	295,803
Operating income	79,846	70,048
Other income (expense):		
Interest charges -		
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(23,672)	(29,914)
Allowance for funds used during construction - borrowed	74	518
Capitalized interest	266	161
Unrealized gain (loss) on interest rate swaps, net	7,456	12,045
Interest income	285	437
Allowance for funds used during construction - equity	200	277
Other income (expense), net	405	1,472
Total other income (expense)	(14,986)	(15,004)
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	64,860	55,044
Equity in earnings (loss) of unconsolidated subsidiaries	(86)	(56)
Income tax benefit (expense)	(21,577)	(19,717)
Income (loss) from continuing operations	43,197	35,271
Income (loss) from discontinued operations, net of tax	—	(5,484)
Net income (loss) available for common stock	$43,197	$29,787
Earnings (loss) per share, Basic -		
Income (loss) from continuing operations, per share	$0.98	$0.81
Income (loss) from discontinued operations, per share	—	(0.13)
Total income (loss) per share, Basic	$0.98	$0.68

Earnings (loss) per share, Diluted -		
Income (loss) from continuing operations, per share	$0.97	$0.80
Income (loss) from discontinued operations, per share	—	(0.12)
Total income (loss) per share, Diluted	$0.97	$0.68
Weighted average common shares outstanding:		
Basic	44,053	43,731
Diluted	44,312	43,969
Dividends paid per share of common stock	$0.380	$0.370

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

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

	Three Months Ended March 31, 2013	2012
	(in thousands)	
Net income (loss) available for common stock	$43,197	$29,787
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax (expense) benefit of $1,117 and $55, respectively)	(1,661)	576
Reclassification adjustments related to defined benefit plan (net of tax of $(175) and $0)	457	—
Reclassification adjustments of cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(236) and $445, respectively)	468	(742)
Other comprehensive income (loss), net of tax	(736)	(166)
Comprehensive income (loss) available for common stock	$42,461	$29,621

See Note 8 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, 2013 (in thousands)	Dec. 31, 2012	March 31, 2012
ASSETS			
Current assets:			
Cash and cash equivalents	$12,397	$15,462	$56,132
Restricted cash and equivalents	6,846	7,916	8,960
Accounts receivable, net	168,783	163,698	143,987
Materials, supplies and fuel	64,189	77,643	63,236
Derivative assets, current	1,630	3,236	17,877
Income tax receivable, net	—	—	10,399
Deferred income tax assets, net, current	38,196	77,231	23,710
Regulatory assets, current	23,422	31,125	56,282
Other current assets	28,260	28,795	26,546
Total current assets	343,723	405,106	407,129
Investments	16,545	16,402	16,451
Property, plant and equipment	3,977,704	3,930,772	3,800,011
Less accumulated depreciation and depletion	(1,210,833)	(1,188,023)	(980,944)
Total property, plant and equipment, net	2,766,871	2,742,749	2,819,067
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,565	3,620	3,787
Derivative assets, non-current	—	510	881
Regulatory assets, non-current	181,119	188,268	186,093
Other assets, non-current	21,367	19,420	21,132
Total other assets, non-current	559,447	565,214	565,289
TOTAL ASSETS	$3,686,586	$3,729,471	$3,807,936

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, 2013	Dec. 31, 2012	March 31, 2012
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$82,437	$84,422	$59,793
Accrued liabilities	140,230	154,389	151,130
Derivative liabilities, current	89,112	96,541	76,389
Accrued income tax, net	1,157	4,936	—
Regulatory liabilities, current	19,020	13,628	35,414
Notes payable	245,000	277,000	225,000
Current maturities of long-term debt	104,637	103,973	8,977
Total current liabilities	681,593	734,889	556,703
Long-term debt, net of current maturities	936,477	938,877	1,272,016
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	367,502	385,908	317,369
Derivative liabilities, non-current	15,237	16,941	43,169
Regulatory liabilities, non-current	126,573	127,656	112,516
Benefit plan liabilities	172,353	167,397	157,623
Other deferred credits and other liabilities	125,958	125,294	123,848
Total deferred credits and other liabilities	807,623	823,196	754,525
Commitments and contingencies (See Notes 6, 9, 11 and 14)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,482,304; 44,278,189; and 44,151,428 shares, respectively	44,482	44,278	44,151
Additional paid-in capital	735,000	733,095	725,512
Retained earnings	519,184	492,869	490,114
Treasury stock, at cost – 41,606; 71,782; and 65,015 shares, respectively	(1,549)	(2,245)	(2,041)
Accumulated other comprehensive income (loss)	(36,224)	(35,488)	(33,044)
Total stockholders' equity	1,260,893	1,232,509	1,224,692
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,686,586	$3,729,471	$3,807,936

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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating activities:		
Net income (loss) available to common stock	$43,197	$29,787
(Income) loss from discontinued operations, net of tax	—	5,484
Income (loss) from continuing operations	43,197	35,271
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	34,781	38,559
Deferred financing cost amortization	1,095	2,719
Derivative fair value adjustments	3,673	1,594
Stock compensation	3,778	1,817
Unrealized mark-to-market (gain) loss on interest rate swaps	(7,456)	(12,045)
Deferred income taxes	20,541	18,083
Allowance for funds used during construction - equity	(200)	(277)
Employee benefit plans	5,548	5,246
Other adjustments, net	3,614	2,243
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	18,519	20,828
Accounts receivable, unbilled revenues and other current assets	(9,166)	9,439
Accounts payable and other current liabilities	(13,637)	(42,368)
Regulatory assets	9,463	(776)
Regulatory liabilities	374	18,938
Contributions to defined benefit pension plans	—	(25,000)
Other operating activities, net	(4,892)	610
Net cash provided by operating activities of continuing operations	109,232	74,881
Net cash provided by (used in) operating activities of discontinued operations	—	21,184
Net cash provided by operating activities	109,232	96,065
Investing activities:		
Property, plant and equipment additions	(63,939)	(67,652)
Other investing activities	1,030	1,105
Net cash provided by (used in) investing activities of continuing operations	(62,909)	(66,547)
Proceeds from sale of discontinued business operations	—	108,837
Net cash provided by (used in) investing activities of discontinued operations	—	(824)
Net cash provided by (used in) investing activities	(62,909)	41,466
Financing activities:		
Dividends paid on common stock	(16,882)	(16,276)
Common stock issued	1,231	764
Short-term borrowings - issuances	78,500	56,453
Short-term borrowings - repayments	(110,500)	(176,453)
Long-term debt - repayments	(1,737)	(1,897)
Other financing activities	—	(2,758)
Net cash provided by (used in) financing activities of continuing operations	(49,388)	(140,167)

Net cash provided by (used in) financing activities of discontinued operations	—	—
Net cash provided by (used in) financing activities	(49,388)	(140,167)
Net change in cash and cash equivalents	(3,065)	(2,636)
Cash and cash equivalents, beginning of period*	15,462	58,768
Cash and cash equivalents, end of period	$12,397	$56,132

*Includes cash of discontinued operations of $37.1 million at Dec. 31, 2011.

See Note 3 for supplemental disclosure of cash flow information.

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

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BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2012 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 2012 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, 2013, Dec. 31, 2012 and March 31, 2012 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 and 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, 2013 and March 31, 2012, and our financial condition as of March 31, 2013, Dec. 31, 2012, and March 31, 2012 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.

On Feb. 29, 2012, we sold our Energy Marketing segment, which resulted in this segment being classified as discontinued operations.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS AND LEGISLATION

Recently Adopted Accounting Standards

Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income, ASU 2013-02

In February 2013, the FASB issued ASU 2013-02 which requires new disclosures for items reclassified out of AOCI. ASU 2013-02 requires disclosure of (1) changes in components of other comprehensive income, (2) for items reclassified out of AOCI and into net income in their entirety, the effect of the reclassification on each affected net income line item and (3) cross references to other disclosures that provide additional detail for components of other comprehensive income that are not reclassified in their entirety to net income. Disclosures are required either on the face of the statements of income or as a separate disclosure in the notes to the financial statements. The new disclosure requirements are effective for interim and annual periods beginning after Dec. 15, 2012. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows. See additional disclosures in Note 8.

Balance Sheet: Disclosure about Offsetting Assets and Liabilities, ASU 2011-11

In December 2011, the FASB issued revised accounting guidance to amend disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve comparability of balance sheets prepared under GAAP and IFRS. The revised disclosure guidance affects all companies that have financial instruments and derivative instruments that are either offset in the balance sheet (i.e., presented on a net basis) or subject to an enforceable master netting and/or similar arrangement. In addition, the revised guidance requires that certain enhanced quantitative and qualitative disclosures are made with respect to a company's netting arrangements and/or rights of offset associated with its financial instruments and/or derivative instruments. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning Jan. 1, 2013. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows. See additional disclosures in Note 12.

Recently Issued Accounting Pronouncements and Legislation

Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date, ASU 2013-04

In March 2013, the FASB issued new disclosure requirements for recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements including disclosure of the nature and amount of the obligations. The new disclosure requirements are effective for interim and annual periods beginning after Dec. 15, 2013. The amendment requires additional details in the notes to financial statements, but will not have any other impact on our financial statements.

Dodd-Frank Wall Street Reform and Consumer Protection Act, SEC Final Rule No. 34-67716

In Aug. 2012, under Dodd-Frank, the SEC adopted new requirements for companies that manufacture or contract to manufacture products that contain certain minerals and metals, known as conflict minerals. The final rules requires all issuers that file reports with the SEC to report supply chain and sourcing information for companies that use conflict minerals on an annual basis. These new requirements will require due diligence efforts in fiscal 2013, with initial disclosure requirements beginning in May 2014. Based on our preliminary analysis, we do not believe that our products contain conflict minerals as defined by the rule; however, our assessment process to determine whether conflict minerals are necessary to the functionality or production of any of our products is not complete.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended	
	March 31, 2013	March 31, 2012
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$31,780	$31,644
Increase (decrease) in capitalized assets associated with asset retirement obligations	$—	$2,826
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(12,768)	$(16,799)
Income taxes, net	$(4,656)	$(1,838)

(4) 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, 2013	Dec. 31, 2012	March 31, 2012
Materials and supplies	$50,401	$43,397	$44,361
Fuel - Electric Utilities	8,445	8,589	7,812
Natural gas in storage held for distribution	5,343	25,657	11,063
Total materials, supplies and fuel	$64,189	$77,643	$63,236

(5) ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

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

Dec. 31, 2012	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$54,482	$23,843	$(527)	$77,798
Gas Utilities	31,495	39,962	(222)	71,235
Power Generation	16	—	—	16
Coal Mining	2,247	—	—	2,247
Oil and Gas	11,622	—	(19)	11,603
Corporate	799	—	—	799
Total	$100,661	$63,805	$(768)	$163,698

March 31, 2012	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$44,356	$19,381	$(585)	$63,152
Gas Utilities	44,287	18,502	(936)	61,853
Power Generation	265	—	—	265
Coal Mining	2,578	—	—	2,578
Oil and Gas	15,014	—	(105)	14,909
Corporate	1,230	—	—	1,230
Total	$107,730	$37,883	$(1,626)	$143,987

(6) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of March 31, 2013, we were in compliance with all of these covenants.

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

	March 31, 2013		Dec. 31, 2012		March 31, 2012	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$95,000	$36,500	$127,000	$36,300	$75,000	$41,200
Term Loan due June 2013	150,000	—	150,000	—	150,000	—
Total	$245,000	$36,500	$277,000	$36,300	$225,000	$41,200

Debt Covenants

Certain debt obligations require compliance with the following covenants at the end of each quarter (dollars in thousands):

	As of March 31, 2013		Covenant Requirement		
Consolidated Net Worth	$1,260,893		Greater than	$946,493	
Recourse Leverage Ratio	52.2	%	Less than	65.0	%

(7) EARNINGS PER SHARE

A reconciliation of share amounts used to compute Earnings (loss) per share is as follows (in thousands):

	Three Months Ended March 31,	
	2013	2012
Income (loss) from continuing operations	$43,197	$35,271
Weighted average shares - basic	44,053	43,731
Dilutive effect of:		
Restricted stock	155	147
Stock options	13	18
Other dilutive effects	91	73
Weighted average shares - diluted	44,312	43,969

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,	
	2013	2012
Stock options	6	127
Restricted stock	34	31
Other stock	—	16
Anti-dilutive shares	40	174

(8) OTHER COMPREHENSIVE INCOME

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

	Location on the Condensed Consolidated Statements of Income	Amount Reclassified from AOCI Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Gains and losses on cash flow hedges:			
Interest rate swaps	Interest expense	$1,796	$1,822
Commodity contracts	Revenue	(1,092)	(3,009)
		704	(1,187)
Income tax	Income tax benefit (expense)	(236)	445
Total reclassification adjustments related to cash flow hedges, net of tax		$468	$(742)
Amortization of defined benefit plans:			
Prior service cost	Utilities - Operations and maintenance	$(31)	$—
	Non-regulated energy operations and maintenance	(32)	—
Actuarial gain (loss)	Utilities - Operations and maintenance	421	—
	Non-regulated energy operations and maintenance	274	—
		632	—
Income tax	Income tax benefit (expense)	(175)	—
Total reclassification adjustments related to defined benefit plans, net of tax		$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, 2011	$(13,802)	$(19,076)	$(32,878)
Other comprehensive income (loss), net of tax	(166)	—	(166)
Ending Balance March 31, 2012	$(13,968)	$(19,076)	$(33,044)
Balance as of December 31, 2012	$(15,713)	$(19,775)	$(35,488)
Other comprehensive income (loss), net of tax	(1,193)	457	(736)
Ending Balance March 31, 2013	$(16,906)	$(19,318)	$(36,224)

(9) 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,	
	2013	2012
Service cost	$1,608	$1,430
Interest cost	3,825	3,687
Expected return on plan assets	(4,654)	(4,084)
Prior service cost	16	22
Net loss (gain)	3,062	2,408
Net periodic benefit cost	$3,857	$3,463

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,	
	2013	2012
Service cost	$419	$402
Interest cost	417	523
Expected return on plan assets	(20)	(19)
Prior service cost (benefit)	(125)	(125)
Net loss (gain)	121	222
Net periodic benefit cost	$812	$1,003

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,	
	2013	2012
Service cost	$348	$246
Interest cost	332	331
Prior service cost	1	1
Net loss (gain)	198	202
Net periodic benefit cost	$879	$780

Contributions

We anticipate that we will make contributions to the benefit plans during 2013 and 2014. Contributions to the Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

	Contributions Made Three Months Ended March 31, 2013	Additional Contributions Anticipated for 2013	Contributions Anticipated for 2014
Defined Benefit Pension Plans	$—	$8,787	$19,922
Non-pension Defined Benefit Postretirement Healthcare Plans	$784	$2,352	$3,350
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$322	$965	$1,463

(10) BUSINESS SEGMENT INFORMATION

Segment information and Corporate activities included in the accompanying Condensed Consolidated Statements of Income and Condensed Consolidated Balance Sheets are below.

On Feb. 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being classified as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been classified as discontinued operations have been reclassified to Corporate activity.

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

Three Months Ended March 31, 2013	External Operating Revenue	Intercompany Operating Revenue	Income (Loss) from Continuing Operations
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
Intercompany eliminations	—	(31,058)	3
Total	$380,671	$—	$43,197

Three Months Ended March 31, 2012	External Operating Revenue	Intercompany Operating Revenue	Income (Loss) from Continuing Operations
Utilities:			
Electric	$156,133	$3,036	$8,746
Gas	180,522	—	15,207
Non-regulated Energy:			
Power Generation	1,178	18,449	6,914
Coal Mining	6,373	8,616	1,000
Oil and Gas	21,645	—	13
Corporate activities [(a)(b)]	—	—	3,391
Intercompany eliminations	—	(30,101)	—
Total	$365,851	$—	$35,271

(a) Income (loss) from continuing operations includes a $4.8 million and a $7.8 million net after-tax non-cash mark-to-market gain for the three months ended March 31, 2013 and 2012, respectively.

(b) Certain indirect corporate costs and inter-segment interest expense after-tax totaling $1.6 million for the three months ended March 31, 2012 were included in the Corporate activities in continuing operations and were not reclassified as discontinued operations.

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

Total Assets (net of inter-company eliminations) as of:	March 31, 2013	Dec. 31, 2012	March 31, 2012
Utilities:			
Electric [(a)]	$2,367,014	$2,387,458	$2,268,524
Gas	752,468	765,165	717,185
Non-regulated Energy:			
Power Generation [(a)]	115,708	119,170	128,225
Coal Mining	82,839	83,810	87,139
Oil and Gas	255,786	258,460	430,851
Corporate activities	112,771	115,408	176,012
Total assets	$3,686,586	$3,729,471	$3,807,936

(a) The PPA under which the Pueblo Airport Generation site owned by Colorado IPP supports Colorado customers is accounted for as a capital lease. Therefore, assets owned by the Power Generation segment are included in Total Assets of Electric Utilities Segment under this accounting for a capital lease.

(11) 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 2012 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 with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate credit facility, project financing floating rate debt and our other long-term debt instruments.

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, 2013, our credit exposure included a $2.3 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 companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 12.

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 on the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue on the accompanying Condensed Consolidated Statements of Income.

We had the following derivatives and related balances for our Oil and Gas segment (dollars in thousands) as of:

	March 31, 2013		Dec. 31, 2012		March 31, 2012	
	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)]	522,000	10,633,000	528,000	8,215,500	522,000	5,001,750
Maximum terms in years [(b)]	0.75	0.5	1	0.75	1.25	1.5
Derivative assets, current	$821	$287	$1,405	$1,831	$406	$8,256
Derivative assets, non-current	$—	$—	$297	$170	$46	$808
Derivative liabilities, current	$250	$1,188	$847	$507	$2,904	$—
Derivative liabilities, non-current	$—	$—	$—	$—	$1,084	$—
Pre-tax accumulated other comprehensive income (loss)	$10	$(2,781)	$206	$873	$(3,566)	$9,064
Cash collateral receivable (payable) included in derivatives	$730	$1,880	$786	$620	$—	$—
Cash collateral included in Other current assets	$723	$2,102	$1,078	$709	$—	$—

(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 March 31, 2013 market prices, a $0.2 million loss would be 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 tolling arrangements, 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. 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 accordance with state commission guidelines. Accordingly, the hedging activity is recognized in the Condensed Consolidated Statements of Income 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 Gas Utilities were as follows, as of:

	March 31, 2013		Dec. 31, 2012		March 31, 2012	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	13,180,000	80	15,350,000	83	11,550,000	81
Natural gas options purchased	440,000	5	2,430,000	2	670,000	12
Natural gas basis swaps purchased	11,350,000	69	12,020,000	72	7,640,000	81

We had the following derivative balances related to the hedges in our Utilities (in thousands) as of:

	March 31, 2013	Dec. 31, 2012	March 31, 2012
Derivative assets, current	$522	$—	$9,215
Derivative assets, non-current	$—	$43	$27
Derivative liabilities, non-current	$—	$—	$6,407
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$4,315	$9,596	$15,223
Cash collateral receivable (payable) included in derivatives	$4,487	$8,576	$17,651
Cash collateral included in Other current assets	$3,295	$4,354	$—
Option premiums and commissions included in derivatives	$350	$1,063	$407

Financing Activities

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. Our interest rate swaps and related balances were as follows (dollars in thousands) as of:

	March 31, 2013		Dec. 31, 2012		March 31, 2012	
	Designated Interest Rate Swaps [(a)]	De-designated Interest Rate Swaps [(b)]	Designated Interest Rate Swaps [(a)]	De-designated Interest Rate Swaps [(b)]	Designated Interest Rate Swaps [(a)]	De-designated Interest Rate Swaps [(b)]
Notional	$150,000	$250,000	$150,000	$250,000	$150,000	$250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	3.75	0.75	4.00	1.00	4.75	1.75
Derivative liabilities, current	$6,982	$80,692	$7,039	$88,148	$6,777	$66,708
Derivative liabilities, non-current	$15,237	$—	$16,941	$—	$18,441	$17,237
Pre-tax accumulated other comprehensive income (loss)	$(22,219)	$—	$(23,980)	$—	$(25,218)	$—
Pre-tax gain (loss)	$—	$7,456	$—	$1,882	$—	$12,045
Cash collateral receivable (payable) included in derivatives	$—	$5,960	$—	$5,960	$—	$—

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(a) These swaps have been designated to $75.0 million of borrowings on our Revolving Credit Facility and $75.0 million of borrowings on our project financing debt at Black Hills Wyoming. The swaps transferred to Black Hills Wyoming such that BHC and Black Hills Wyoming are both jointly and severally liable for the amount of those obligations. These swaps are priced using three-month LIBOR, matching the floating portion of the related swaps.

(b) Maximum terms in years reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. If extended, de-designated swaps totaling $100.0 million notional terminate in 6 years and de-designated swaps totaling $150.0 million notional terminate in 16 years.

Collateral requirements based on our corporate credit rating apply to $50.0 million of our de-designated swaps. At our current credit ratings, we are required to post collateral for any amount by which the swaps' negative mark-to-market fair value exceeds $20.0 million. If our senior unsecured credit rating drops to BB+ or below by S&P, or to Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swaps' negative mark-to-market fair value. We had $6.0 million cash collateral posted at March 31, 2013.

Based on March 31, 2013 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $7.0 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.

(12) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

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, 3 and 4 included in our 2012 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 the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity option contracts for our Oil and Gas segment are valued under the market approach and 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 under the market approach using 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 Level 2 disclosure.

Utilities Segment:

- The commodity contracts for our Utilities, 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 since 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 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. The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis (in thousands):

	As of March 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
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
Cash equivalents [(a)]	12,397	—	—	—	12,397
Total	$12,397	$3,239	$—	$(1,609)	$14,027
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

(a) Level 1 assets and liabilities are described in Note 13.

	As of Dec. 31, 2012					
	Level 1	Level 2	Level 3		Cash Collateral and Counterparty Netting	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$378	$—		$—	$378
Basis Swaps -- Oil	—	1,325	—		—	1,325
Options -- Gas	—	—	—		—	—
Basis Swaps -- Gas	—	2,000	—		—	2,000
Commodity derivatives —Utilities	—	—	43	(b)	—	43
Cash equivalents (a)	15,462	—	—		—	15,462
Total	$15,462	$3,703	$43		$—	$19,208
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$1,131	$—		$(336)	$795
Basis Swaps -- Oil	—	502	—		(450)	52
Options -- Gas	—	—	—		—	—
Basis Swaps -- Gas	—	1,127	—		(620)	507
Commodity derivatives — Utilities	—	10,162	—		(10,162)	—
Interest rate swaps	—	118,088	—		(5,960)	112,128
Total	$—	$131,010	$—		$(17,528)	$113,482

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(a) Level 1 assets and liabilities are described in Note 13.

(b) The significant unobservable inputs used in the fair value measurement of the long-term OTC contracts are based on the average of price quotes from an independent third party market participant and the OTC contract broker. The unobservable inputs are long-term natural gas prices. Significant changes to these inputs along with the contract term would impact the derivative asset/liability and regulatory asset/liability, but will not impact the results of operations until the contract is settled under the original terms of the contract. The contracts will be classified as Level 2 once settlement is within 60 months of maturity and quoted market prices from a market exchange are available.

	As of March 31, 2012					
	Level 1	Level 2	Level 3		Cash Collateral and Counterparty Netting	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$404	$—		$—	$404
Basis Swaps -- Oil	—	48	—		—	48
Options -- Gas	—	—	—		—	—
Basis Swaps -- Gas	—	9,064	—		—	9,064
Commodity derivatives — Utilities	—	(8,412)	3	(b)	17,651	9,242
Cash equivalents (a)	55,919	—	—		—	55,919
Total	$55,919	$1,104	$3		$17,651	$74,677
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$1,347	$—		$—	$1,347
Basis Swaps -- Oil	—	2,641	—		—	2,641
Options -- Gas	—	—	—		—	—
Basis Swaps -- Gas	—	—	—		—	—
Commodity derivatives — Utilities	—	6,359	48	(b)	—	6,407
Interest rate swaps	—	109,163	—		—	109,163
Total	$—	$119,510	$48		$—	$119,558

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(a) Level 1 assets and liabilities are described in Note 13.

(b) The significant unobservable inputs used in the fair value measurement of the long-term OTC contracts are based on the average of price quotes from an independent third party market participant and the OTC contract broker. The unobservable inputs are long-term natural gas prices. Significant changes to these inputs along with the contract term would impact the derivative asset/liability and regulatory asset/liability, but will not impact the results of operations until the contract is settled under the original terms of the contract. The contracts will be classified as Level 2 once settlement is within 60 months of maturity and quoted market prices from a market exchange are available.

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 and reflect 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 amounts do not include net cash collateral on deposit in margin accounts at March 31, 2013, Dec. 31, 2012, and March 31, 2012, 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 11.

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

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

As of Dec. 31, 2012

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$2,874	$—
Commodity derivatives	Derivative assets — non-current	510	—
Commodity derivatives	Derivative liabilities — current	—	1,993
Commodity derivatives	Derivative liabilities — non-current	—	821
Interest rate swaps	Derivative liabilities — current	—	7,038
Interest rate swaps	Derivative liabilities — non-current	—	16,941
Total derivatives designated as hedges		$3,384	$26,793
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$362	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	1,180	4,957
Commodity derivatives	Derivative liabilities — non-current	406	5,153
Interest rate swaps	Derivative liabilities — current	—	94,108
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$1,948	$104,218

As of March 31, 2012

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$8,662	$—
Commodity derivatives	Derivative assets — non-current	854	—
Commodity derivatives	Derivative liabilities — current	—	2,904
Commodity derivatives	Derivative liabilities — non-current	—	1,084
Interest rate swaps	Derivative liabilities — current	—	6,777
Interest rate swaps	Derivative liabilities — non-current	—	18,441
Total derivatives designated as hedges		$9,516	$29,206
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$8,436
Commodity derivatives	Derivative assets — non-current	—	(27)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	6,407
Interest rate swaps	Derivative liabilities — current	—	66,708
Interest rate swaps	Derivative liabilities — non-current	—	17,237
Total derivatives not designated as hedges		$—	$98,761

Derivatives Offsetting

It is our policy to offset in our Condensed Consolidated Balance Sheets contracts which provide for legally enforceable netting for our accounts receivable and payable and derivative activities. The tables below do not reflect accounts receivable or accounts payable subject to master netting agreements.

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and reflect the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under the terms of our master netting agreements. Additionally, the amounts reflect cash collateral on deposit in margin accounts at March 31, 2013, Dec. 31, 2012, and March 31, 2012, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities as of March 31, 2013 (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Condensed Consolidated Balance Sheets	Cash Collateral included in Derivatives	Net Amount of Total Derivative Assets on Condensed Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$75	$—	$(75)	$—
Oil and Gas - Crude Options	11	—	(11)	—
Oil and Gas - Natural Gas Basis Swaps	148	—	(148)	—
Utilities	1,897	(1,375)	—	522
Total derivative assets subject to a master netting agreement or similar arrangement	2,131	(1,375)	(234)	522
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	761	—	—	761
Oil and Gas - Crude Options	60	—	—	60
Oil and Gas - Natural Gas Basis Swaps	287	—	—	287
Utilities	—	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	1,108	—	—	1,108
Total derivative assets	$3,239	$(1,375)	$(234)	$1,630

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Condensed Consolidated Balance Sheets	Cash Collateral included in Derivatives	Net Amount of Total Derivative Liabilities on Condensed Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$612	$—	$(612)	$—
Oil and Gas - Crude Options	204	—	(204)	—
Oil and Gas - Natural Gas Basis Swaps	2,028	—	(2,028)	—
Utilities	5,862	(1,375)	(4,487)	—
Interest Rate Swaps	—	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	8,706	(1,375)	(7,331)	—
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	58	—	—	58

Oil and Gas - Crude Options	192	—	—	192
Oil and Gas - Natural Gas Basis Swaps	1,188	—	—	1,188
Utilities	—	—	—	—
Interest Rate Swaps	108,871	—	(5,960)	102,911
Total derivative liabilities not subject to a master netting agreement or similar arrangement	110,309	—	(5,960)	104,349
Total derivative liabilities	$119,015	$(1,375)	$(13,291)	$104,349

Offsetting of derivative assets and derivative liabilities as of Dec. 31, 2012 (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Condensed Consolidated Balance Sheets	Cash Collateral included in Derivatives	Net Amount of Total Derivative Assets on Condensed Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$76	$—	$—	$76
Oil and Gas - Crude Options	93	—	—	93
Oil and Gas - Natural Gas Basis Swaps	172	—	—	172
Utilities	1,629	(1,586)	—	43
Total derivative assets subject to a master netting agreement or similar arrangement	1,970	(1,586)	—	384
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	1,249	—	—	1,249
Oil and Gas - Crude Options	285	—	—	285
Oil and Gas - Natural Gas Basis Swaps	1,828	—	—	1,828
Utilities	—	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	3,362	—	—	3,362
Total derivative assets	$5,332	$(1,586)	$—	$3,746

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Condensed Consolidated Balance Sheets	Cash Collateral included in Derivatives	Net Amount of Total Derivative Liabilities on Condensed Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$449	$—	$(449)	$—
Oil and Gas - Crude Options	337	—	(337)	—
Oil and Gas - Natural Gas Basis Swaps	620	—	(620)	—
Utilities	10,162	(1,586)	(8,576)	—
Interest Rate Swaps	—	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	11,568	(1,586)	(9,982)	—
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	52	—	—	52

Oil and Gas - Crude Options	795	—	—	795
Oil and Gas - Natural Gas Basis Swaps	507	—	—	507
Utilities	—	—	—	—
Interest Rate Swaps	118,088	—	(5,960)	112,128
Total derivative liabilities not subject to a master netting agreement or similar arrangement	119,442	—	(5,960)	113,482
Total derivative liabilities	$131,010	$(1,586)	$(15,942)	$113,482

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Offsetting of derivative assets and derivative liabilities as of March 31, 2012 (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Condensed Consolidated Balance Sheets	Cash Collateral included in Derivatives	Net Amount of Total Derivative Assets on Condensed Consolidated Balance Sheets
Subject to master netting agreements or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$—	$—	$—	$—
Oil and Gas - Crude Options	—	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—	—
Utilities	(8,409)	—	17,651	9,242
Total derivative assets subject to a master netting agreement or similar arrangement	(8,409)	—	17,651	9,242
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	48	—	—	48
Oil and Gas - Crude Options	404	—	—	404
Oil and Gas - Natural Gas Basis Swaps	9,064	—	—	9,064
Utilities	—	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	9,516	—	—	9,516
Total derivative assets	$1,107	$—	$17,651	$18,758

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Condensed Consolidated Balance Sheets	Cash Collateral included in Derivatives	Net Amount of Total Derivative Liabilities on Condensed Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$—	$—	$—	$—
Oil and Gas - Crude Options	—	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—	—
Utilities	6,407	—	—	6,407
Interest Rate Swaps	—	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	6,407	—	—	6,407
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	2,641	—	—	2,641

Oil and Gas - Crude Options	1,347	—	—	1,347
Oil and Gas - Natural Gas Basis Swaps	—	—	—	—
Utilities	—	—	—	—
Interest Rate Swaps	109,163	—	—	109,163
Total derivative liabilities not subject to a master netting agreement or similar arrangement	113,151	—	—	113,151
Total derivative liabilities	$119,558	$—	$—	$119,558

Derivative assets and derivative liabilities and collateral held by counterparty as of March 31, 2013 (in thousands):

			Gross Amounts Not Offset on Condensed Consolidated Balance Sheets	
Contract Type		Net Amount of Total Derivative Assets	Cash Collateral Received	Net Amount with Counterparty
Asset:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	1,108	—	1,108
Utilities	Counterparty A	522	—	522
		$1,630	$—	$1,630

			Gross Amounts Not Offset on Condensed Consolidated Balance Sheets	
Contract Type		Net Amount of Total Derivative Liabilities	Cash Collateral Paid	Net Amount with Counterparty
Liabilities				
Oil and Gas	Counterparty A	$—	$(2,825)	$(2,825)
Oil and Gas	Counterparty B	1,438	—	1,438
Utilities	Counterparty A	—	(3,295)	(3,295)
Interest Rate Swap	Counterparty D	4,266	—	4,266
Interest Rate Swap	Counterparty E	26,754	—	26,754
Interest Rate Swap	Counterparty F	11,841	—	11,841
Interest Rate Swap	Counterparty G	24,905	—	24,905
Interest Rate Swap	Counterparty H	14,625	—	14,625
Interest Rate Swap	Counterparty I	20,520	—	20,520
		$104,349	$(6,120)	$98,229

Derivative assets and derivative liabilities and collateral held by counterparty as of Dec. 31, 2012 (in thousands):

			Gross Amounts Not Offset on Condensed Consolidated Balance Sheets	
Contract Type		Net Amount of Total Derivative Assets	Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$341	$—	$341
Oil and Gas	Counterparty B	3,362	—	3,362
Utilities	Counterparty A	43	—	43
		$3,746	$—	$3,746

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Condensed Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(1,787)	$(1,787)
Oil and Gas	Counterparty B	1,354	—	1,354
Utilities	Counterparty A	—	(4,354)	(4,354)
Interest Rate Swap	Counterparty D	4,588	—	4,588
Interest Rate Swap	Counterparty E	29,245	—	29,245
Interest Rate Swap	Counterparty F	12,721	—	12,721
Interest Rate Swap	Counterparty G	26,520	—	26,520
Interest Rate Swap	Counterparty H	16,809	—	16,809
Interest Rate Swap	Counterparty I	22,245	—	22,245
		$113,482	$(6,141)	$107,341

Derivative assets and derivative liabilities and collateral held by counterparty as of March 31, 2012 (in thousands):

Contract Type		Net Amount of Total Derivative Assets	Gross Amounts Not Offset on Condensed Consolidated Balance Sheets Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	9,516	—	9,516
Utilities	Counterparty A	9,242	—	9,242
		$18,758	$—	$18,758

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Condensed Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	3,988	—	3,988
Utilities	Counterparty A	6,407	—	6,407
Interest Rate Swap	Counterparty D	4,810	—	4,810
Interest Rate Swap	Counterparty E	27,137	—	27,137
Interest Rate Swap	Counterparty F	13,027	—	13,027
Interest Rate Swap	Counterparty G	24,617	—	24,617
Interest Rate Swap	Counterparty H	19,808	—	19,808
Interest Rate Swap	Counterparty I	19,764	—	19,764
		$119,558	$—	$119,558

A description of our derivative activities is included in Note 11. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income.

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income was as follows (in thousands):

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)		$—

Three Months Ended March 31, 2012

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	$(762)	Interest expense	$(1,822)		$—
Commodity derivatives	1,283	Revenue	3,009		—
Total	$521		$1,187		$—

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedge instruments on our Condensed Consolidated Statements of Income was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2013 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$7,456
Interest rate swaps - realized	Interest expense	(3,427)
		$4,029

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives	Three Months Ended March 31, 2012 Amount of Gain/(Loss) on Derivatives

	Recognized in Income	Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$12,045
Interest rate swaps - realized	Interest expense	(3,205)
		$8,840

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(13) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments are as follows (in thousands) as of:

	March 31, 2013		Dec. 31, 2012		March 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$12,397	$12,397	$15,462	$15,462	$56,132	$56,132
Restricted cash and equivalents [(a)]	$6,846	$6,846	$7,916	$7,916	$8,960	$8,960
Notes payable [(a)]	$245,000	$245,000	$277,000	$277,000	$225,000	$225,000
Long-term debt, including current maturities [(b)]	$1,041,114	$1,208,909	$1,042,850	$1,231,559	$1,280,993	$1,439,724

(a) Fair value approximates carrying 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.

(14) COMMITMENTS AND CONTINGENCIES

Commitments and Contingencies

There have been no significant changes to commitments and contingencies, other than those described below, from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2012 Annual Report on Form 10-K.

The following purchase power and power sales agreements were renewed during the first quarter of 2013:

- Cheyenne Light renewed an agreement with Basin Electric whereby Cheyenne Light will receive 40 megawatts of capacity and energy from Basin Electric through Sept. 30, 2014. This agreement is subject to FERC approval which is expected during the second quarter of 2013.

- Cheyenne Light renewed an agreement with Basin Electric whereby Cheyenne Light provides 40 megawatts of capacity and energy through Sept. 30, 2014. This agreement is subject to FERC approval which is expected during the second quarter of 2013.

Other Commitments

Construction of Cheyenne Prairie, a 132 megawatt natural gas-fired electric generating facility, by Cheyenne Light and Black Hills Power is expected to cost approximately $222.0 million, exclusive of financing costs. Construction is expected to be completed by Sept. 30, 2014. As of March 31, 2013, committed contracts for equipment purchases and for construction were 28 percent and 13 percent complete, respectively.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills. Our utility subsidiary, Black Hills Power, subsequently received written damage claims from the State of Wyoming and one landowner seeking recovery for alleged injury to timber, grass, fencing, fire suppression and rehabilitation costs of approximately $8.0 million. On

April 16, 2013, thirty-four private landowners filed suit in United States District Court for the District of Wyoming, asserting similar claims, based upon allegations of negligence, common law nuisance and trespass. The suit seeks recovery of both actual and exemplary damages in an unspecified amount. Our investigation into the cause and origin of the fire is pending. We expect to deny and will vigorously defend all claims arising out of the lawsuit, pending the completion of our investigation. Given the uncertainty of litigation, however, a loss related to the fire and the litigation is reasonably possible. We cannot reasonably estimate the amount of a potential loss because our investigation is ongoing. Further claims may be presented by other parties. Although we cannot predict the outcome of our investigation or the viability of alleged claims, based on information currently available, management believes that any such claims, if determined adversely to us, will not have a material adverse effect on our financial condition or results of operation.

Sale of Enserco Energy Inc.

In December 2012, we agreed to arbitrate certain claims that we believe are properly characterized as purchase price adjustments related to the sale of Enserco, but objected to the arbitration of additional claims that we believe are not properly characterized as purchase price adjustments. After joint discussions of the parties with the arbitrator in January 2013, the arbitrator advised the parties that it would not arbitrate the claims to which we objected. On April 11, 2013, the buyer filed a petition in the Colorado District Court for the City and County of Denver, Colorado, seeking an order compelling arbitration on all of the disputed claims. We responded by requesting the court to deny the buyer's petition. The filing of this petition does not alter our characterization or evaluation of the original claim.

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, 2013, 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, 2013:

- 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, 2013, the restricted net assets at our Utilities Group were approximately $205.9 million.

- As required by the covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has maintained restricted shareholders' equity of at least $100.0 million.

Guarantees

As of Dec. 31, 2012, the Company had provided a guarantee for up to $33.3 million of Colorado Electric's performance and payment obligations relating to the purchase of wind turbines for the Colorado Electric wind power generation project. The guarantee expired March 29, 2013 upon fulfillment of all contractual obligations.

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

We are an 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 203,000 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 35,000 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 536,000 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, Wyo. 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, and 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, 2013 and 2012, and our financial condition as of March 31, 2013, Dec. 31, 2012, and March 31, 2012 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 59.

The following business group and segment information does not include intercompany eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated. As a result of the sale of Enserco on Feb. 29, 2012, the reportable segment previously reported as Energy Marketing is classified as discontinued operations.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. Income from continuing operations for the three months ended March 31, 2013 was $43.2 million, or $0.97 per share, compared to Income from continuing operations of $35.3 million, or $0.80 per share, reported for the same period in 2012. The 2013 Income from continuing operations included a $4.8 million after-tax non-cash unrealized mark-to-market gain on certain interest rate swaps. The 2012 Income from continuing operations included a $7.8 million after-tax non-cash unrealized mark-to-market gain on the same interest rate swaps and an after-tax write-off of $1.0 million of deferred financing costs related to the previous Revolving Credit Facility.

Net income for the three months ended March 31, 2013 was $43.2 million, or $0.97 per share, compared to Net income of $29.8 million, or $0.68 per share, for the same period in 2012. Net income for the three months ended March 31, 2013 and 2012 include the same significant items discussed above.

	Three Months Ended March 31,		
	2013	2012	Variance
	(in thousands)		
Revenue			
Utilities	$362,442	$339,691	$22,751
Non-regulated Energy	49,287	56,261	(6,974)
Intercompany eliminations	(31,058)	(30,101)	(957)
	$380,671	$365,851	$14,820
Net income (loss)			
Electric Utilities	$12,356	$8,746	$3,610
Gas Utilities	18,483	15,207	3,276
Utilities	30,839	23,953	6,886
Power Generation	5,644	6,914	(1,270)
Coal Mining	1,065	1,000	65
Oil and Gas	(53)	13	(66)
Non-regulated Energy	6,656	7,927	(1,271)
Corporate activities and eliminations [(a)(b)]	5,702	3,391	2,311
Income (loss) from continuing operations	43,197	35,271	7,926
Income (loss) from discontinued operations, net of tax	—	(5,484)	5,484
Net income (loss)	$43,197	$29,787	$13,410

(a) Corporate activities include a $4.8 million and a $7.8 million net after-tax non-cash mark-to-market gain on interest rate swaps for the three months ended March 31, 2013 and 2012, respectively.

(b) Certain indirect corporate costs and inter-segment interest expenses after-tax totaling $1.6 million for the three months ended March 31, 2012 were included in the Corporate activities in continuing operations and were not reclassified as discontinued operations.

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Business Group highlights for 2013 include:

Utilities Group

- Quarter-to-date utility results were favorably impacted by colder weather, particularly at the Gas Utilities. Heating degree days for the quarter were 30 percent higher compared to the same quarter in 2012. Heating degree days for the quarter were 6 percent higher than normal for 2013 compared to 19 percent lower than normal for 2012.

- Construction and infrastructure work for Cheyenne Prairie, a natural gas-fired electric generating facility to serve Cheyenne Light and Black Hills Power customers began in April 2013. The 132 megawatt generation project is expected to cost approximately $222 million, with up to $15 million of construction financing costs, for a total of $237 million. Through March 31, 2013, $52.7 million was expended, and the project is on schedule to be placed into service in the fourth quarter of 2014.

- On Jan. 17, 2013, the SDPUC approved a stipulation for interim rates effective April 1, 2013, subject to refund, for the use of a construction financing rider for the South Dakota portion of costs for Cheyenne Prairie in lieu of the traditional allowance for funds used during construction. Public hearings with the SDPUC are scheduled in the third quarter of 2013. The WPSC approved a similar construction financing rider for our Wyoming customers during 2012 and the Electric Utilities recorded additional gross margins of approximately $0.6 million for the three months ended March 31, 2013 relating to this rider.

- On Dec. 17, 2012, Black Hills Power filed a request with the SDPUC seeking a $13.7 million increase in annual electric revenues. Public hearings with the SDPUC are scheduled in the fourth quarter of 2013. We expect to implement interim rates, subject to refund, in June 2013.

- On April 30, 2013, Colorado Electric filed its electric resource plan with the CPUC, addressing its projected resource requirements through 2019. The resource plan identifies a 40 megawatt, simple-cycle, natural gas-fired turbine as the replacement capacity for the retirement of the coal-fired, 42 megawatt W.N. Clark power plant, consistent with the requirements of the Colorado Clean Air - Clean Jobs Act. A CPCN has been submitted to the CPUC requesting approval for the new generating capacity. If approved, this plant is expected to be constructed at the Pueblo Airport Generation Station and placed into service in the first quarter of 2017. The resource plan also recommends the retirement of Pueblo Units 5 and 6 as of Dec. 31, 2013. A CPCN has been submitted to the CPUC seeking approval to retire these plants, which were placed in service in the 1940s.

- On April 23, 2013, Colorado Electric issued a request for proposals for up to 30 megawatts of wind energy delivered to its electric system in southern Colorado. Adding another 30 megawatts of wind generation will assist Colorado Electric towards meeting Colorado's renewable energy standard as mandated by state law, which requires each publicly owned utilities to deliver 30 percent of its energy as renewable energy by 2020. The request seeks to allow bidders to take advantage of the recent extension of the federal production tax credits for qualifying renewable technologies.

Non-regulated Energy Group

- Oil and Gas reported a 27 percent reduction in total volumes sold, reflecting the 2012 sale of the Williston Basin oil and gas assets. Results benefited from a 15 percent increase in average hedge price received for crude oil during the first quarter of 2013 compared to the first quarter of 2012, partially offset by an 18 percent decrease in average hedge price received for natural gas.

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Oil and Gas is drilling the first of two wells in the Mancos Shale formation in the Piceance Basin. The wells are part of a transaction through which we will earn up to approximately 20,000 net acres of additional Mancos Shale leaseholds in the Piceance Basin in exchange for drilling and completing the wells.

Corporate Activities

- Consolidated interest expense decreased by approximately $6.2 million for the three months ended March 31, 2013 due primarily to the repayment of approximately $225 million of debt in 2012.

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $7.5 million and $12.0 million for the three months ended March 31, 2013 and 2012, respectively.

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.

Electric Utilities

	Three Months Ended March 31,		
	2013	2012	Variance
	(in thousands)		
Revenue — electric	$150,373	$146,281	$4,092
Revenue — gas	12,257	12,888	(631)
Total revenue	162,630	159,169	3,461
Fuel, purchased power and cost of gas — electric	65,689	65,598	91
Purchased gas — gas	6,438	8,118	(1,680)
Total fuel, purchased power and cost of gas	72,127	73,716	(1,589)
Gross margin — electric	84,684	80,683	4,001
Gross margin — gas	5,819	4,770	1,049
Total gross margin	90,503	85,453	5,050
Operations and maintenance	38,835	39,230	(395)
Depreciation and amortization	19,161	18,932	229
Total operating expenses	57,996	58,162	(166)
Operating income	32,507	27,291	5,216
Interest expense, net	(14,397)	(13,220)	(1,177)
Other income (expense), net	285	718	(433)
Income tax benefit (expense)	(6,039)	(6,043)	4
Income (loss) from continuing operations	$12,356	$8,746	$3,610

The following tables summarize revenue, quantities generated and purchased, quantities sold, degree days and power plant availability for our Electric Utilities:

	Three Months Ended March 31,	
Revenue - Electric (in thousands)	2013	2012
Residential:		
Black Hills Power	$16,442	$15,476
Cheyenne Light	9,330	8,470
Colorado Electric	24,121	22,616
Total Residential	49,893	46,562
Commercial:		
Black Hills Power	17,484	16,808
Cheyenne Light	12,767	13,957
Colorado Electric	21,151	19,127
Total Commercial	51,402	49,892
Industrial:		
Black Hills Power	6,010	6,020
Cheyenne Light	4,855	3,069
Colorado Electric	9,637	9,232
Total Industrial	20,502	18,321
Municipal:		
Black Hills Power	714	698
Cheyenne Light	458	426
Colorado Electric	2,547	2,664
Total Municipal	3,719	3,788
Total Retail Revenue - Electric	125,516	118,563
Contract Wholesale:		
Total Contract Wholesale - Black Hills Power	5,767	4,905
Off-system Wholesale:		
Black Hills Power	6,250	11,273
Cheyenne Light	2,682	2,513
Colorado Electric	1,107	233
Total Off-system Wholesale	10,039	14,019
Other Revenue:		
Black Hills Power	7,150	7,090
Cheyenne Light	566	612
Colorado Electric	1,335	1,092
Total Other Revenue	9,051	8,794
Total Revenue - Electric	$150,373	$146,281

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	Three Months Ended March 31,	
Quantities Generated and Purchased (in MWh)	2013	2012
Generated —		
Coal-fired:		
Black Hills Power [(a)]	427,015	499,792
Cheyenne Light	172,312	127,153
Colorado Electric [(b)]	—	57,307
Total Coal-fired	599,327	684,252
Gas, Oil and Wind:		
Black Hills Power	3,120	363
Cheyenne Light	—	—
Colorado Electric [(c)]	42,227	1,632
Total Gas, Oil and Wind	45,347	1,995
Total Generated:		
Black Hills Power	430,135	500,155
Cheyenne Light	172,312	127,153
Colorado Electric	42,227	58,939
Total Generated	644,674	686,247
Purchased —		
Black Hills Power	388,199	514,534
Cheyenne Light	201,845	231,619
Colorado Electric	455,138	401,127
Total Purchased	1,045,182	1,147,280
Total Generated and Purchased:		
Black Hills Power	818,334	1,014,689
Cheyenne Light	374,157	358,772
Colorado Electric	497,365	460,066
Total Generated and Purchased	1,689,856	1,833,527

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(a) Decrease is primarily the result of the suspension of operations at Ben French as of Dec. 31, 2012.

(b) Decrease is primarily a result of the suspension of operations at W.N. Clark as of Dec. 31, 2012.

(c) Increase is primarily due to higher usage of our gas-fired generation at the Pueblo Airport Generating Facility as a result of the suspension of operations at W.N. Clark and a decrease in available economy energy, and energy from the Busch Ranch wind project which was placed into commercial operation in the fourth quarter of 2012.

	Three Months Ended March 31,	
Quantity Sold (in MWh)	2013	2012
Residential:		
Black Hills Power	160,970	150,428
Cheyenne Light	75,456	71,837
Colorado Electric	155,436	154,052
Total Residential	391,862	376,317
Commercial:		
Black Hills Power	175,617	170,093
Cheyenne Light	129,429	149,939
Colorado Electric	170,705	165,391
Total Commercial	475,751	485,423
Industrial:		
Black Hills Power	91,632	95,735
Cheyenne Light	69,952	44,774
Colorado Electric	78,549	81,242
Total Industrial	240,133	221,751
Municipal:		
Black Hills Power	7,783	7,568
Cheyenne Light	2,595	2,582
Colorado Electric	18,046	25,169
Total Municipal	28,424	35,319
Total Retail Quantity Sold	1,136,170	1,118,810
Contract Wholesale:		
Total Contract Wholesale - Black Hills Power	103,784	89,048
Off-system Wholesale:		
Black Hills Power	238,447	458,230
Cheyenne Light	70,308	66,709
Colorado Electric	31,777	2,608
Total Off-system Wholesale	340,532	527,547
Total Quantity Sold:		
Black Hills Power	778,233	971,102
Cheyenne Light	347,740	335,841
Colorado Electric	454,513	428,462
Total Quantity Sold	1,580,486	1,735,405
Losses and Company Use:		
Black Hills Power	40,101	43,587
Cheyenne Light	26,417	22,930
Colorado Electric	42,852	31,605
Total Losses and Company Use	109,370	98,122

Total Quantity Sold	1,689,856	1,833,527

Degree Days	Three Months Ended March 31, 2013		2012	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Black Hills Power	3,210	— %	2,711	(16)%
Cheyenne Light	3,162	5 %	2,761	(8)%
Colorado Electric	2,750	5 %	2,294	(13)%
Cooling Degree Days:				
Black Hills Power	—	— %	—	— %
Cheyenne Light	—	— %	—	— %
Colorado Electric	—	— %	—	— %

Electric Utilities Power Plant Availability	Three Months Ended March 31, 2013	2012
Coal-fired plants [(a)]	96.9 %	90.8 %
Other plants	98.6 %	95.0 %
Total availability	97.8 %	92.9 %

(a) 2012 includes planned overhauls at Wygen II.

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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,	
	2013	2012
Revenue - Gas (in thousands):		
Residential	$7,532	$7,630
Commercial	3,608	3,810
Industrial	898	1,237
Other Sales Revenue	219	211
Total Revenue - Gas	$12,257	$12,888
Gross Margin (in thousands):		
Residential	$3,960	$3,226
Commercial	1,492	1,173
Industrial	148	164
Other Gross Margin	219	207
Total Gross Margin	$5,819	$4,770
Volumes Sold (Dth):		
Residential	1,093,000	969,678
Commercial	625,937	580,940
Industrial	226,947	237,140
Total Volumes Sold	1,945,884	1,787,758

Results of Operations for the Electric Utilities for the Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012: Income from continuing operations for the Electric Utilities was $12.4 million for the three months ended March 31, 2013 compared to $8.7 million for the three months ended March 31, 2012 as a result of:

Gross margin increased primarily due to a $1.6 million increase related to electric rate adjustments, a $0.6 million increase related to gas rate adjustments, $1.3 million from stronger retail and wholesale demand, a $0.6 million increase related to the newly approved Wyoming construction financing rider, and $0.4 million from increased gas usage as a result of colder weather.

Operations and maintenance decreased primarily due to reduced costs resulting from plant suspensions, the timing of repairs and maintenance costs, partially offset by employee compensation and benefit costs compared to the same period in the prior year.

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

Interest expense, net increased primarily due to increase in corporate allocations related to debt costs and lower AFUDC as compared to the same period in the prior year.

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

Income tax benefit (expense): The effective tax rate decreased due to a favorable benefit from research and development tax credits, including the retroactive effect of the full year 2012 estimated benefit.

Gas Utilities

	Three Months Ended March 31,		
	2013	2012	Variance
	(in thousands)		
Natural gas — regulated	$191,951	$172,169	$19,782
Other — non-regulated services	7,861	8,353	(492)
Total revenue	199,812	180,522	19,290
Natural gas — regulated	120,380	108,116	12,264
Other — non-regulated services	3,717	3,869	(152)
Total cost of sales	124,097	111,985	12,112
Gross margin	75,715	68,537	7,178
Operations and maintenance	33,226	31,299	1,927
Depreciation and amortization	6,503	6,157	346
Total operating expenses	39,729	37,456	2,273
Operating income (loss)	35,986	31,081	4,905
Interest expense, net	(6,277)	(6,540)	263
Other income (expense), net	12	11	1
Income tax benefit (expense)	(11,238)	(9,345)	(1,893)
Income (loss) from continuing operations	$18,483	$15,207	$3,276

The following tables include revenue, gross margin, volumes sold and degree days for our Gas Utilities:

Revenue (in thousands)	Three Months Ended March 31, 2013	2012
Residential:		
Colorado	$19,794	$22,018
Nebraska	48,852	40,924
Iowa	38,751	34,570
Kansas	25,765	21,421
Total Residential	133,162	118,933
Commercial:		
Colorado	3,660	4,194
Nebraska	16,247	14,100
Iowa	17,775	15,773
Kansas	8,789	6,735
Total Commercial	46,471	40,802
Industrial:		
Colorado	48	52
Nebraska	205	289
Iowa	745	745
Kansas	932	922
Total Industrial	1,930	2,008
Transportation:		
Colorado	401	346
Nebraska	4,716	3,799
Iowa	1,539	1,250
Kansas	2,049	1,868
Total Transportation	8,705	7,263
Other Sales Revenue:		
Colorado	(74)	29
Nebraska	614	575
Iowa	112	123
Kansas	1,031	2,436
Total Other Sales Revenue	1,683	3,163
Total Regulated Revenue	191,951	172,169
Non-regulated Services	7,861	8,353
Total Revenue	$199,812	$180,522

Gross Margin (in thousands)	Three Months Ended March 31,	
	2013	2012
Residential:		
Colorado	$6,238	$5,686
Nebraska	18,311	15,591
Iowa	13,589	12,195
Kansas	10,204	9,120
Total Residential	48,342	42,592
Commercial:		
Colorado	989	916
Nebraska	4,635	3,883
Iowa	4,452	3,797
Kansas	2,644	2,170
Total Commercial	12,720	10,766
Industrial:		
Colorado	30	30
Nebraska	54	61
Iowa	82	71
Kansas	224	222
Total Industrial	390	384
Transportation:		
Colorado	401	347
Nebraska	4,716	3,799
Iowa	1,539	1,250
Kansas	2,049	1,868
Total Transportation	8,705	7,264
Other Sales Margins:		
Colorado	(74)	29
Nebraska	614	575
Iowa	112	123
Kansas	761	2,321
Total Other Sales Margins	1,413	3,048
Total Regulated Gross Margin	71,570	64,054
Non-regulated Services	4,145	4,483
Total Gross Margin	$75,715	$68,537

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Volumes Sold (in Dth)	Three Months Ended March 31,	
	2013	2012
Residential:		
Colorado	2,921,335	2,603,401
Nebraska	5,737,673	4,352,817
Iowa	5,290,366	4,151,466
Kansas	3,216,306	2,659,674
Total Residential	17,165,680	13,767,358
Commercial:		
Colorado	576,276	526,794
Nebraska	2,198,798	1,780,631
Iowa	2,805,673	2,227,795
Kansas	1,277,134	993,005
Total Commercial	6,857,881	5,528,225
Industrial:		
Colorado	9,737	10,552
Nebraska	30,680	40,901
Iowa	142,324	129,142
Kansas	188,821	188,897
Total Industrial	371,562	369,492
Total Volumes Sold	24,395,123	19,665,075
Transportation:		
Colorado	412,709	361,873
Nebraska	8,682,315	8,140,894
Iowa	5,679,157	5,187,496
Kansas	4,052,018	4,359,921
Total Transportation	18,826,199	18,050,184
Other Volumes:		
Colorado	—	—
Nebraska	—	—
Iowa	—	—
Kansas (a)	55,010	24,450
Total Other Volumes	55,010	24,450
Total Volumes and Transportation Sold	43,276,332	37,739,709

(a) Other volumes represent wholesale customers.

	Three Months Ended March 31,			
	2013		2012	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	2,872	3%	2,350	(16)%
Nebraska	3,129	3%	2,400	(21)%
Iowa	3,743	11%	2,799	(20)%
Kansas [(a)]	2,550	3%	2,040	(18)%
Combined [(b)]	3,306	6%	2,536	(20)%

(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.

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 Nov. 1 and ends around March 31.

Results of Operations for the Gas Utilities for the Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012: Income from continuing operations for the Gas Utilities was $18.5 million for the three months ended March 31, 2013 compared to Income from continuing operations of $15.2 million for the three months ended March 31, 2012 as a result of:

Gross margin increased primarily due to colder weather than in the same period during the prior year. Heating degree days were 30 percent higher for the three months ended March 31, 2013 compared to the same period in the prior year and 6 percent higher than normal.

Operations and maintenance increased primarily due to an increase in employee compensation and benefit costs and uncollectible accounts receivable compared 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 lower debt, partially offset by an increase in corporate allocations related to debt costs.

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

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

Regulatory Matters — Utilities Group

The following summarizes our recent state and federal rate case and initial surcharge orders (dollars in millions):

	Type of Service	Date Requested	Revenue Amount Requested
Iowa Gas [(a)]	Gas	12/2012	$0.9
Black Hills Power [(b)]	Electric	12/2012	$13.7
Black Hills Power [(c)]	Electric	12/2012	$9.2

(a) On March 15, 2013, the IUB approved the Capital Infrastructure Automatic Adjustment Mechanism filed by Iowa Gas in December 2012. Approval was obtained for recovery of our 2012 capital investments. The mechanism will be effective in April 2013 and will result in a revenue increase of approximately $0.2 million in 2013.

(b) As described in our 2012 Annual Report on Form 10-K, in December 2012 Black Hills Power filed a rate case with the SDPUC. We expect to implement interim rates, subject to refund, on June 16, 2013. Public hearings with the SDPUC are scheduled to commence Oct. 8, 2013.

(c) On Jan. 17, 2013, the SDPUC approved a stipulation for interim rates effective April 1, 2013, subject to refund, for the use of a construction financing rider for the South Dakota portion of costs for the Cheyenne Prairie in lieu of the traditional allowance for funds used during construction. Public hearings with the SDPUC are scheduled to commence Sept. 16, 2013.

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,		
	2013	2012	Variance
	(in thousands)		
Revenue	$20,360	$19,627	$733
Operations and maintenance	7,791	7,132	659
Depreciation and amortization	1,226	1,114	112
Total operating expense	9,017	8,246	771
Operating income	11,343	11,381	(38)
Interest expense, net	(2,674)	(4,743)	2,069
Other (expense) income	1	5	(4)
Income tax (expense) benefit	(3,026)	271	(3,297)
Income (loss) from continuing operations	$5,644	$6,914	$(1,270)

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

	Three Months Ended March 31, 2013		2012	
Contracted power plant fleet availability:				
Coal-fired plant	100.0	%	100.0	%
Natural gas-fired plants	98.6	%	99.6	%
Total availability	98.9	%	99.7	%

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Results of Operations for Power Generation for the Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012: Income from continuing operations for the Power Generation segment was $5.6 million for the three months ended March 31, 2013 compared to Income from continuing operations of $6.9 million for the same period in 2012 as a result of:

Revenue increased due to an increase in megawatt hours delivered at a higher price.

Operations and maintenance increased primarily due to increased repairs and maintenance costs and employee compensation and benefit costs.

Depreciation and amortization was comparable to the same period in the prior year. The generating facility located in Pueblo, Colo. is accounted for as a capital lease under GAAP; as such, depreciation expense for the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net decreased due to lower debt balances at lower interest rates partially offset by an increase in corporate allocations related to debt costs.

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

Income tax (expense) benefit: The effective tax rate increased compared to the same period in the prior year primarily due to a favorable state tax true-up in 2012.

Coal Mining

	Three Months Ended March 31,		
	2013	2012	Variance
	(in thousands)		
Revenue	$13,583	$14,989	$(1,406)
Operations and maintenance	10,151	11,478	(1,327)
Depreciation, depletion and amortization	2,865	3,696	(831)
Total operating expenses	13,016	15,174	(2,158)
Operating income (loss)	567	(185)	752
Interest (expense) income, net	(131)	755	(886)
Other income	613	881	(268)
Income tax benefit (expense)	16	(451)	467
Income (loss) from continuing operations	$1,065	$1,000	$65

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

	Three Months Ended March 31,	
	2013	2012
Tons of coal sold	1,053	1,103
Cubic yards of overburden moved	1,059	2,642

Results of Operations for Coal Mining for the Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012: Income from continuing operations for the Coal Mining segment was $1.1 million for the three months ended March 31, 2013 compared to Income from continuing operations of $1.0 million for the same period in 2012 as a result of:

Revenue decreased primarily due to lower average price per ton and lower tons sold as a result of customer power plant suspensions and outages. Approximately 50 percent of our coal production is sold under contracts that include price adjustments based on actual mining costs. Our mining costs have trended down due to lower operating costs, thereby decreasing our price per ton for these customers. Most of our remaining production is sold under contracts where the sales price escalates periodically based on published indices.

Operations and maintenance decreased primarily from mining in areas with lower overburden due to a revised mine plan, including decreased fuel costs and headcount reductions.

Depreciation, depletion and amortization decreased primarily due to lower depreciation of mine reclamation asset retirement costs.

Interest (expense) income, net reflects decreased interest income primarily due to a decrease in an inter-company notes receivable upon payment of a dividend to our parent.

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

Income tax benefit (expense): The effective tax rate decreased primarily due to the impact of percentage depletion and a net favorable benefit from research and development credits, including the retroactive effect of the full year 2012 estimated benefit.

Oil and Gas

	Three Months Ended March 31,		
	2013	2012	Variance
	(in thousands)		
Revenue	$15,344	$21,645	$(6,301)
Operations and maintenance	10,255	10,834	(579)
Depreciation, depletion and amortization	5,367	9,323	(3,956)
Total operating expenses	15,622	20,157	(4,535)
Operating income (loss)	(278)	1,488	(1,766)
Interest income (expense), net	79	(1,605)	1,684
Other income (expense), net	(77)	29	(106)
Income tax benefit (expense)	223	101	122
Income (loss) from continuing operations	$(53)	$13	$(66)

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

Three Months Ended
March 31,

	2013	2012
Production:		
Bbls of oil sold	96,803	145,477
Mcf of natural gas sold	1,732,950	2,388,475
Gallons of NGL sold	945,814	814,585
Mcf equivalent sales	2,448,884	3,377,706

	Three Months Ended March 31, 2013	2012
Average price received: [a]		
Oil/Bbl	$89.73	$77.99
Gas/Mcf	$2.96	$3.61
NGL/gallon	$0.94	$0.95
Depletion expense/Mcfe	$1.78	$2.47

(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, 2013				Three Months Ended March 31, 2012			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.29	$0.34	$0.42	$2.05	$0.97	$0.32	$0.36	$1.65
Piceance	0.65	0.65	0.33	1.63	(0.03)	0.49	0.15	0.61
Powder River	1.26	—	1.24	2.50	1.38	—	1.31	2.69
Williston	0.83	—	1.07	1.90	0.71	—	1.25	1.96
All other properties	0.70	—	0.38	1.08	1.68	—	0.08	1.76
Total weighted average	$1.08	$0.23	$0.65	$1.96	$0.89	$0.21	$0.60	$1.70

Results of Operations for Oil and Gas for the Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012: Loss from continuing operations for the Oil and Gas segment was $0.1 million for the three months ended March 31, 2013 compared to Income from continuing operations of $0.0 million for the same period in 2012 as a result of:

Revenue decreased primarily due to a 27 percent decrease in volumes sold as a result of our Williston Basin asset sale in 2012, a natural production decline in our Mancos formation wells and an 18 percent decrease in the average price received for natural gas sold, partially offset by a 15 percent increase in the average price received for crude oil sold.

Operations and maintenance decreased primarily due to lower non-operated costs and lower production and ad valorem taxes on lower revenues.

Depreciation, depletion and amortization decreased primarily due to a lower depletion rate per Mcfe and lower volumes. The decreased depletion rate is primarily driven by the sale of our Williston Basin assets in 2012.

Interest income (expense), net reflects lower interest expense primarily due to decreased debt as a result of proceeds from the 2012 sale of the Williston Basin assets.

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, 2013 Compared to Three Months Ended March 31, 2012: Income from continuing operations for Corporate was $5.7 million for the three months ended March 31, 2013 compared to Income from continuing operations of $3.4 million for the three months ended March 31, 2012. The variance from the prior year was primarily due to market interest rate changes impacting unrealized, non-cash mark-to-market gains on certain interest rate swaps; the allocation of debt related costs included in Corporate activities for the three months ended March 31, 2012 now allocated to our segments for the three months ended March 31, 2013 in order to better align the capital structure of our operating segments; and costs originally allocated to our Energy Marketing segment, which could not be reclassified to discontinued operations in accordance with GAAP, which were included in Corporate activities for the three months ended March 31, 2012.

Discontinued Operations

Results of Operations for Discontinued Operations for the Three Months Ended March 31, 2013, Compared to Three Months Ended March 31, 2012:

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. Loss from discontinued operations, net of tax, for the three months ended March 31, 2012 was $5.5 million relating to additional operating costs to discontinue the operations, including an after-tax loss on sale of $1.6 million including transaction related costs, net of tax benefit, of $2.2 million.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2012 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 2012 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 Gas Utilities 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.

All amounts are presented on a pre-tax basis unless otherwise indicated.

Cash Flow Activities

The following table summarizes our cash flows for the three months ended March 31, 2013 and 2012 (in thousands):

Cash provided by (used in):	2013	2012	Increase (Decrease)
Operating activities	$109,232	$96,065	$13,167
Investing activities	$(62,909)	$41,466	$(104,375)
Financing activities	$(49,388)	$(140,167)	$90,779

Year-to-Date 2013 Compared to Year-to-Date 2012

Operating Activities

Net cash provided by operating activities was $13.2 million higher for the three months ended March 31, 2013 than for the same period in 2012 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $15.4 million higher for the three months ended March 31, 2013 than for the same period in the prior year.

- Net inflows from operating assets and liabilities were $5.6 million for the three months ended March 31, 2013, a decrease of $0.5 million from the same period in the prior year. Changes are normal working capital changes influenced by variable weather, declines in natural gas prices for the Utilities Group, expiration of the PPA with PSCo, and receipt of $8.4 million from a government grant relating to the Busch Ranch wind project.

- No cash contributions to the defined benefit pension plan were made in the first quarter of 2013 compared to $25.0 million in 2012.

- A $21.2 million decrease in net cash inflows from discontinued operations in 2013 compared to 2012.

Investing Activities

Net cash used by investing activities was $62.9 million for the three months ended March 31, 2013 compared to net cash provided by investing activities of $41.5 million for the same period in 2012 for a variance of $104.4 million.

- The variance was driven by cash proceeds received from the 2012 sale of Enserco of $108.8 million.

Financing Activities

Net cash used in financing activities for the three months ended March 31, 2013 was $49.4 million compared to net cash used in financing activities for the same period in 2012 of $140.2 million for a variance of $90.8 million.

- The variance was primarily driven by the proceeds from the sale of Enserco which was used to pay down short-term borrowings on the Revolving Credit Facility of approximately $110 million in 2012.

Dividends

Dividends paid on our common stock totaled $16.9 million for the three months ended March 31, 2013, or $0.38 per share. On April 22, 2013, our board of directors declared a quarterly dividend of $0.38 per share payable June 1, 2013, which is equivalent to an annual dividend rate of $1.52 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 revolving corporate credit facility which matures on Feb. 1, 2017 that has an accordion feature which 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 under the agreement are determined based upon our credit ratings. At our current credit rating of BBB-, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 0.50 percent, 1.50 percent and 1.50 percent, respectively. A commitment fee is charged on the unused amount of the Revolving Credit Facility which is 0.25 percent based on current credit ratings.

Our Revolving Credit Facility at March 31, 2013 had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at March 31, 2013	Letters of Credit at March 31, 2013	Available Capacity at March 31, 2013
Revolving Credit Facility	Feb. 1, 2017	$500.0	$95.0	$36.5	$368.5

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 certain minimum net worth amounts and recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is the ratio of our recourse debt, letters of credit and guarantees issued over our total capital which includes the balance in the numerator 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, 2013.

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.

Future Financing Plans

During the next three years, BHC plans to consider completion of the following financing activities to take advantage of the low interest rate environment:

- Extend our $150 million and $100 million term loans;
- Analyze early refinancing of our $250 million, 9 percent senior unsecured bonds that mature in May 2014; and
- Review long-term financing options for the estimated $222 million Cheyenne Prairie capital project.

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 interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the Condensed Consolidated Statements of Income. For the three months ended March 31, 2013, we recorded $7.5 million pre-tax unrealized non-cash mark-to-market gain on the swaps. The mark-to-market value on these swaps was a liability of $80.7 million at March 31, 2013. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves divided by the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of 6 years and 16 years and have early termination dates ranging from Dec. 15, 2013 to Dec. 31, 2013. We anticipate extending these agreements upon their early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended we will cash settle these swaps for an amount equal to their fair values on the early termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 3.75 years. These swaps have been designated as cash flow hedges, 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 $22.2 million at March 31, 2013.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and 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. 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. 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 most restrictive financial covenants of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed 0.65 to 1.00 and a minimum consolidated net worth of $625 million plus 50 percent of aggregate consolidated net income since Jan. 1, 2005. As of March 31, 2013, we were in compliance with these covenants.

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. 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 percent of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. 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 of March 31, 2013, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $205.9 million.

As required by a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings, the parent of Black Hills Electric Generation which is the parent of Black Hills Wyoming, has restricted shareholders' equity of at least $100.0 million. In addition, Black Hills Wyoming holds $6.8 million of restricted cash associated with the project financing requirements.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2012 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

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

The following table represents the credit ratings, outlook and risk profile of Black Hills Corporation's Senior Unsecured Debt at March 31, 2013:

Rating Agency	Rating	Outlook
S&P	BBB-	Positive
Moody's	Baa3	Positive
Fitch	BBB-	Stable

The following table represents the credit ratings of Black Hills Power's First Mortgage Bonds at March 31, 2013:

Rating Agency	Rating
S&P	BBB+
Moody's	A3
Fitch	A-

Capital Requirements

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

	Expenditures for the Three Months Ended March 31, 2013	Total 2013 Planned Expenditures	Total 2014 Planned Expenditures	Total 2015 Planned Expenditures
Utilities:				
Electric Utilities	$43,460	$284,200	$230,500	$127,600
Gas Utilities	8,680	59,800	58,000	43,000
Non-regulated Energy:				
Power Generation	705	3,200	4,800	2,400
Coal Mining	2,166	7,100	6,000	5,100
Oil and Gas	4,298	98,300	84,300	109,100
Corporate	856	7,500	6,500	5,700
	$60,165	$460,100	$390,100	$292,900

We continue to evaluate potential future acquisitions and other growth opportunities which 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 19 of our Notes to the Consolidated Financial Statements in our 2012 Annual Report on Form 10-K.

Purchase Power and Power Sales Agreements

The following purchase power and power sales agreements were renewed during first quarter of 2013:

- Cheyenne Light renewed an agreement with Basin Electric whereby Cheyenne Light will receive 40 megawatts of capacity and energy from Basin Electric through Sept. 30, 2014. This agreement is subject to FERC approval which is expected during the second quarter of 2013.

- Cheyenne Light renewed an agreement with Basin Electric whereby Cheyenne Light provides 40 megawatts of capacity and energy through Sept. 30, 2014. This agreement is subject to FERC approval which is expected during the second quarter of 2013.

Construction Commitments

Construction of Cheyenne Prairie, a 132 megawatt natural gas-fired electric generating facility, by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million, with up to $15 million of construction financing costs, for a total of $237 million. Construction is expected to be completed by Sept. 30, 2014. As of March 31, 2013, contracts for equipment purchases and for construction were 28 percent and 13 percent committed, respectively.

Sale of Enserco Energy Inc.

In December 2012, we agreed to arbitrate certain claims that we believe are properly characterized as purchase price adjustments related to the sale of Enserco, but objected to the arbitration of additional claims that we believe are not properly characterized as purchase price adjustments. After joint discussions of the parties with the arbitrator in January 2013, the arbitrator advised the parties that it would not arbitrate the claims to which we objected. On April 11, 2013, the buyer filed a petition in the Colorado District Court for the City and County of Denver, Colorado, seeking an order compelling arbitration on all of the disputed claims. We responded by requesting the court to deny the buyer’s petition. The filing of this petition does not alter our characterization or evaluation of the original claim.

Guarantees

Except as noted below, there have been no significant changes to guarantees from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2012 Annual Report on Form 10-K.

As of Dec. 31, 2012, the Company had provided a guarantee for up to $33.3 million of Colorado Electric’s performance and payment obligations relating to the purchase of wind turbines for the Colorado Electric wind power generation project. The guarantee expired March 29, 2013 upon fulfillment of all contractual obligations.

New Accounting Pronouncements

Other than the pronouncements reported in our 2012 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 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 is 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 is 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 2012 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2012 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 the effect of volatile 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. The fair value of our Utilities Group's derivative contracts is summarized below (in thousands) as of:

	March 31, 2013	Dec. 31, 2012	March 31, 2012
Net derivative (liabilities) assets	$(3,965)	$(8,533)	$(14,816)
Cash collateral	7,782	12,930	17,651
	$3,817	$4,397	$2,835

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Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2013, 2014 and 2015 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at March 31, 2013 were as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2013					
Swaps - MMBtu	—	1,233,000	1,246,000	1,154,000	3,633,000
Weighted Average Price per MMBtu	$—	$3.55	$3.33	$3.50	$3.46
2014					
Swaps - MMBtu	1,040,000	1,495,000	1,735,000	1,735,000	6,005,000
Weighted Average Price per MMBtu	$3.74	$3.72	$3.98	$3.99	$3.88
2015					
Swaps - MMBtu	630,000	365,000	—	—	995,000
Weighted Average Price per MMBtu	$4.27	$4.00	$—	$—	$4.17

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2013					
Swaps - Bbls	—	21,000	15,000	15,000	51,000
Weighted Average Price per Bbl	$—	$108.96	$110.20	$101.75	$107.20
Puts - Bbls	—	36,000	39,000	36,000	111,000
Weighted Average Price per Bbl	$—	$78.96	$79.81	$80.63	$79.80
Calls - Bbls	—	36,000	39,000	36,000	111,000
Weighted Average Price per Bbl	$—	$97.17	$97.08	$97.25	$97.16
2014					
Swaps - Bbls	51,000	60,000	57,000	45,000	213,000
Weighted Average Price per Bbl	$94.50	$90.65	$90.55	$90.75	$91.57
Puts - Bbls	—	—	—	—	—
Weighted Average Price per Bbl	$—	$—	$—	$—	$—
Calls - Bbls	—	—	—	—	—
Weighted Average Price per Bbl	$—	$—	$—	$—	$—
2015					
Swaps - Bbls	36,000	—	—	—	36,000
Weighted Average Price per Bbl	$90.27	$—	$—	$—	$90.27

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 3 of our 2012 Annual Report on Form 10-K and in Note 11 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Our interest rate swaps and related balances were as follows (dollars in thousands) as of:

	March 31, 2013		Dec. 31, 2012		March 31, 2012	
	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*
Notional	$150,000	$ 250,000	$150,000	$ 250,000	$150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	3.75	0.75	4.00	1.00	4.75	1.75
Derivative liabilities, current	$6,982	$ 80,692	$7,039	$ 88,148	$6,777	$ 66,708
Derivative liabilities, non-current	$15,237	$ —	$16,941	$ —	$18,441	$ 17,237
Pre-tax accumulated other comprehensive income (loss)	$(22,219)	$ —	$(23,980)	$ —	$(25,218)	$ —
Pre-tax gain (loss)	$—	$ 7,456	$—	$ 1,882	$—	$ 12,045
Cash collateral receivable (payable) included in derivatives	$—	$ 5,960	$—	$ 5,960	$—	$ —

* Maximum terms in years for our de-designated interest rate swaps reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. When extended annually, de-designated swaps totaling $100.0 million terminate in 6 years and de-designated swaps totaling $150.0 million terminate in 16 years.

Based on March 31, 2013 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $7.0 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 (Exchange Act)) as of March 31, 2013. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended March 31, 2013, 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 19 in Item 8 of our 2012 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 Annual Report on Form 10-K for the year ended Dec. 31, 2012.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans for Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
Jan. 1, 2013 - Jan. 31, 2013	3,051	$36.34	—	—
Feb. 1, 2013 - Feb. 28, 2013	33,631	$40.90	—	—
March 1, 2013 - March 31, 2013	2,636	$42.25	—	—
Total	39,318	$40.63	—	—

(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Omnibus Incentive Plan for the payment of taxes associated with the vesting of shares of restricted stock.

ITEM 4. Mine Safety Disclosures

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

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 2.1*	Stock Purchase Agreement by and between Twin Eagle Resource Management, LLC and Black Hills Non-Regulated Holdings LLC for the purchase of capital stock of Enserco Energy Inc., dated January 18, 2012 (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2012).
Exhibit 2.2*	Purchase and Sale Agreement, dated as of August 23, 2012, by and among Black Hills Exploration and Production, Inc. and other sellers and QEP Energy Company, as Purchaser (excluding exhibits and certain schedules, which the Registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request) (filed as Exhibit 2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2012).
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).
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).
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Exhibit 95	Mine Safety and Health Administration Safety Data
Exhibit 101	Financial Statements for XBRL Format

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

SIGNATURES

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

BLACK HILLS CORPORATION

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

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

Dated: May 3, 2013

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