BLACK HILLS CORP /SD/
Form 10-Q
August 06, 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 June 30, 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 July 31, 2013	
Common stock, $1.00 par value	44,518,338	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, and Black Hills Gas Resources, Inc. and Black Hills Plateau Production, LLC, direct wholly-owned subsidiaries of Black Hills Exploration and Production, Inc.
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 Minerals	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

CTII	The 40 megawatt Gillette CT, a simple-cycle, gas-fired combustion turbine owned by Black Hills Wyoming
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.
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 of natural gas
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 1/7 Mcfe
NOL	Net Operating Loss
OTC	Over-the-counter
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado
Revolving Credit Facility	Our $500 million credit facility which matures in 2017
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
WPSC	Wyoming Public Service Commission

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands, except per share and per share amounts)			
Revenue	$279,826	$242,363	$660,497	$608,214
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of gas sold	99,172	63,452	267,345	220,635
Operations and maintenance	64,977	59,563	130,667	124,323
Non-regulated energy operations and maintenance	20,890	20,713	42,219	43,308
Depreciation, depletion and amortization	35,152	41,431	69,933	79,990
Taxes - property, production and severance	10,069	9,478	20,449	20,988
Impairment of long-lived assets	—	26,868	—	26,868
Other operating expenses	529	267	1,001	1,463
Total operating expenses	230,789	221,772	531,614	517,575
Operating income	49,037	20,591	128,883	90,639
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(23,369)	(27,762)	(47,041)	(57,676)
Allowance for funds used during construction - borrowed	410	963	484	1,481
Capitalized interest	272	131	538	292
Unrealized gain (loss) on interest rate swaps, net	18,793	(15,552)	26,249	(3,507)
Interest income	475	627	760	1,064
Allowance for funds used during construction - equity	42	195	242	472
Other income (expense), net	474	888	879	2,360
Total other income (expense), net	(2,903)	(40,510)	(17,889)	(55,514)
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	46,134	(19,919)	110,994	35,125
Equity in earnings (loss) of unconsolidated subsidiaries	—	22	(86)	(34)
Income tax benefit (expense)	(15,616)	7,574	(37,193)	(12,143)
Income (loss) from continuing operations	30,518	(12,323)	73,715	22,948
Income (loss) from discontinued operations, net of tax	—	(1,160)	—	(6,644)
Net income (loss) available for common stock	$30,518	$(13,483)	$73,715	$16,304
Earnings (loss) per share, Basic -				
Income (loss) from continuing operations, per share	$0.69	$(0.28)	$1.67	$0.52
Income (loss) from discontinued operations, per share	—	(0.03)	—	(0.15)

Total income (loss) per share, Basic	$0.69	$(0.31)	$1.67	$0.37
Earnings (loss) per share, Diluted -				
Income (loss) from continuing operations, per share	$0.69	$(0.28)	$1.66	$0.52
Income (loss) from discontinued operations, per share	—	(0.03)	—	(0.15)
Total income (loss) per share, Diluted	$0.69	$(0.31)	$1.66	$0.37
Weighted average common shares outstanding:				
Basic	44,172	43,799	44,113	43,765
Diluted	44,412	43,799	44,363	43,984
Dividends paid per share of common stock	$0.380	$0.370	$0.760	$0.740

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

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

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Net income (loss) available for common stock	$30,518	$(13,483)	$73,715	$16,304
Other comprehensive income (loss), net of tax:				
Fair value adjustment on derivatives designated as cash flow hedges (net of tax (expense) benefit of $(2,174) and $(167) for the three months ended 2013 and 2012 and $(1,057) and $(112) for the six months ended 2013 and 2012, respectively)	3,878	11	2,217	587
Reclassification adjustments related to defined benefit plan (net of tax of $(268) and $0 for the three months ended 2013 and 2012 and $(443) and $0 for the six months ended 2013 and 2012, respectively)	364	—	821	—
Reclassification adjustments of cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(647) and $432 for the three months ended 2013 and 2012 and $(883) and $877 for the six months ended 2013 and 2012, respectively)	1,201	(619)	1,669	(1,361)
Other comprehensive income (loss), net of tax	5,443	(608)	4,707	(774)
Comprehensive income (loss) available for common stock	$35,961	$(14,091)	$78,422	$15,530

See Note 7 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 June 30, 2013	Dec. 31, 2012	June 30, 2012
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$30,633	$15,462	$40,110
Restricted cash and equivalents	7,279	7,916	4,772
Accounts receivable, net	132,726	163,698	109,157
Materials, supplies and fuel	73,768	77,643	61,455
Derivative assets, current	903	3,236	16,595
Income tax receivable, net	146	—	12,141
Deferred income tax assets, net, current	38,764	77,231	30,401
Regulatory assets, current	26,258	31,125	34,781
Other current assets	27,595	28,795	26,591
Total current assets	338,072	405,106	336,003
Investments	16,566	16,402	16,208
Property, plant and equipment	4,066,502	3,930,772	3,863,380
Less: accumulated depreciation and depletion	(1,234,578)	(1,188,023)	(1,006,827)
Total property, plant and equipment, net	2,831,924	2,742,749	2,856,553
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,508	3,620	3,731
Derivative assets, non-current	—	510	1,770
Regulatory assets, non-current	180,646	188,268	186,886
Other assets, non-current	22,402	19,420	19,733
Total other assets, non-current	559,952	565,214	565,516
TOTAL ASSETS	$3,746,514	$3,729,471	$3,774,280

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

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

	As of June 30, 2013	Dec. 31, 2012	June 30, 2012
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$88,071	$84,422	$59,739
Accrued liabilities	135,819	154,389	158,240
Derivative liabilities, current	69,270	96,541	85,675
Accrued income tax, net	—	4,936	—
Regulatory liabilities, current	20,550	13,628	16,785
Notes payable	100,000	277,000	225,000
Current maturities of long-term debt	255,507	103,973	227,590
Total current liabilities	669,217	734,889	773,029
Long-term debt, net of current maturities	958,559	938,877	1,044,891
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	387,674	385,908	316,393
Derivative liabilities, non-current	12,384	16,941	42,077
Regulatory liabilities, non-current	129,013	127,656	114,593
Benefit plan liabilities	177,216	167,397	162,530
Other deferred credits and other liabilities	129,763	125,294	124,482
Total deferred credits and other liabilities	836,050	823,196	760,075
Commitments and contingencies (See Notes 5, 8, 10 and 13)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,516,472; 44,278,189; and 44,176,520 shares, respectively	44,517	44,278	44,177
Additional paid-in capital	737,729	733,095	727,613
Retained earnings	532,810	492,869	460,324
Treasury stock, at cost – 42,480; 71,782; and 69,657 shares, respectively	(1,587)	(2,245)	(2,177)
Accumulated other comprehensive income (loss)	(30,781)	(35,488)	(33,652)
Total stockholders' equity	1,282,688	1,232,509	1,196,285
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,746,514	$3,729,471	$3,774,280

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

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

	Six Months Ended June 30,	
	2013	2012
Operating activities:	(in thousands)	
Net income (loss) available to common stock	$73,715	$16,304
(Income) loss from discontinued operations, net of tax	—	6,644
Income (loss) from continuing operations	73,715	22,948
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	69,933	79,990
Deferred financing cost amortization	2,188	4,050
Impairment of long-lived assets	—	26,868
Derivative fair value adjustments	4,248	(4,895)
Stock compensation	6,896	3,269
Unrealized (gain) loss on interest rate swaps, net	(26,249)	3,507
Deferred income taxes	36,607	11,200
Employee benefit plans	11,096	10,492
Other adjustments, net	8,967	3,820
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	8,940	22,609
Accounts receivable, unbilled revenues and other operating assets	28,377	64,028
Accounts payable and other current liabilities	(26,739)	(60,233)
Contributions to defined benefit pension plans	—	(25,000)
Other operating activities, net	(594)	(7,138)
Net cash provided by operating activities of continuing operations	197,385	155,515
Net cash provided by (used in) operating activities of discontinued operations	—	21,184
Net cash provided by operating activities	197,385	176,699
Investing activities:		
Property, plant and equipment additions	(147,230)	(148,807)
Other investing activities	2,006	4,095
Net cash provided by (used in) investing activities of continuing operations	(145,224)	(144,712)
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	(145,224)	(36,699)
Financing activities:		
Dividends paid on common stock	(33,774)	(32,583)
Common stock issued	2,570	1,510
Short-term borrowings - issuances	133,300	56,453
Short-term borrowings - repayments	(310,300)	(176,453)
Long-term debt - issuances	275,000	—
Long-term debt - repayments	(103,786)	(10,418)
Other financing activities	—	2,833
Net cash provided by (used in) financing activities of continuing operations	(36,990)	(158,658)
Net cash provided by (used in) financing activities of discontinued operations	—	—
Net cash provided by (used in) financing activities	(36,990)	(158,658)
Net change in cash and cash equivalents	15,171	(18,658)

Cash and cash equivalents, beginning of period	15,462	58,768	*
Cash and cash equivalents, end of period	$30,633	$40,110	

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

See Note 2 for supplemental disclosure of cash flow information.
The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 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 June 30, 2013, Dec. 31, 2012, and June 30, 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. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2013 and June 30, 2012, and our financial condition as of June 30, 2013, Dec. 31, 2012, and June 30, 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.

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) 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 7.

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. 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 11.

Recently Issued Accounting Pronouncements and Legislation

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

In July 2013, the FASB issued an amendment to accounting for income taxes which provides guidance on financial statement presentation of an unrecognized tax benefit when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. The objective in issuing this amendment is to eliminate diversity in practice resulting from a lack of guidance on this topic in current GAAP. Under the amendment, an entity must present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the financial statements as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward except under certain conditions. The amendment is effective for fiscal years beginning after Dec. 15, 2013, and interim periods within those years and should be applied to all unrecognized tax benefits that exist as of the effective date. The adoption of this standard is not expected to have an impact on our financial position, results of operations or cash flows.

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes, ASU 2013-10

In July 2013, the FASB issued an amendment to accounting for derivatives and hedges to permit the Fed Funds Effective Swap Rate to be used as a U.S. benchmark interest rate for hedge accounting purposes effective for new or re-designated hedging relationships entered into on or after July 17, 2013. The amendment also removed the restriction on using different benchmark rates for similar hedges. We will evaluate the impact of this amendment upon re-designating or entering into a new hedging relationship.

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 August 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 rule requires all issuers that file reports with the SEC, and use conflict minerals, to report supply chain and sourcing information on an annual basis. These new requirements will require due diligence efforts in 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.

(2) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Six Months Ended	
	June 30, 2013	June 30, 2012
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$45,000	$52,204
Increase (decrease) in capitalized assets associated with asset retirement obligations	$—	$3,406
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(44,191)	$(55,364)
Income taxes, net	$(5,406)	$(383)

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(3) MATERIALS, SUPPLIES AND FUEL

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

	June 30, 2013	Dec. 31, 2012	June 30, 2012
Materials and supplies	$51,334	$43,397	$41,963
Fuel - Electric Utilities	6,817	8,589	8,089
Natural gas in storage held for distribution	15,617	25,657	11,403
Total materials, supplies and fuel	$73,768	$77,643	$61,455

(4) ACCOUNTS RECEIVABLE

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

June 30, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$45,250	$24,290	$(630)	$68,910
Gas Utilities	38,749	13,192	(1,074)	50,867
Power Generation	157	—	—	157
Coal Mining	2,503	—	—	2,503
Oil and Gas	8,373	—	(19)	8,354
Corporate	1,935	—	—	1,935
Total	$96,967	$37,482	$(1,723)	$132,726

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

June 30, 2012	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$36,336	$25,726	$(620)	$61,442
Gas Utilities	20,627	11,085	(950)	30,762
Power Generation	197	—	—	197
Coal Mining	1,982	—	—	1,982
Oil and Gas	13,749	—	(105)	13,644
Corporate	1,130	—	—	1,130
Total	$74,021	$36,811	$(1,675)	$109,157

(5) NOTES PAYABLE AND LONG-TERM DEBT

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

	June 30, 2013		Dec. 31, 2012		June 30, 2012	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$100,000	$43,157	$127,000	$36,300	$75,000	$36,256
Term Loan due June 2013	—	—	150,000	—	150,000	—
Total	$100,000	$43,157	$277,000	$36,300	$225,000	$36,256

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of June 30, 2013, we were in compliance with all of these covenants.

Replacement of Notes Payable and Long-term Term Loan

On June 21, 2013, we entered into a new $275 million term loan expiring on June 19, 2015. This new term loan replaced the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on Sept. 30, 2013, and $25 million in short-term borrowing under our Revolving Credit Facility. At June 30, 2013, the cost of borrowing under this new term loan was 1.375 percent based on LIBOR plus a margin of 1.125 percent. The covenants of the new term loan are substantially the same as the Revolving Credit Facility.

Debt Covenants

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

	As of June 30, 2013	Covenant Requirement	
Consolidated Net Worth	$1,282,688	Greater than	$961,752
Recourse Leverage Ratio	51.5%	Less than	65.0%

(6) EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Income (loss) from continuing operations	$30,518	$(12,323)	$73,715	$22,948
Weighted average shares - basic	44,172	43,799	44,113	43,765
Dilutive effect of:				
Restricted stock	125	—	140	150
Stock options	12	—	13	15
Other dilutive effects	103	—	97	54
Weighted average shares - diluted	44,412	43,799	44,363	43,984

Below is a discussion of our potentially dilutive shares that were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive.

Due to our net loss for the quarter ended June 30, 2012, potentially dilutive securities, consisting of outstanding stock options, restricted common stock, restricted stock units, non-vested performance-based share awards and warrants, were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 13,081 options to purchase shares of common stock, 152,318 vested and non-vested restricted stock shares, 34,248 warrants and other performance shares were excluded from the computations for the three months ended June 30, 2012.

In addition to these dilutive shares excluded due to our net loss for the quarter ended June 30, 2012, the following outstanding securities were not included in the computation of diluted earnings (loss) per share as their effect would have been anti-dilutive (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Stock options	10	99	8	113
Restricted stock	18	66	26	48
Other stock	—	42	—	29
Anti-dilutive shares	28	207	34	190

(7) OTHER COMPREHENSIVE INCOME (LOSS)

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

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Gains (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$1,820	$1,843	$3,616	$3,665
Commodity contracts	Revenue	28	(2,894)	(1,064)	(5,903)
		1,848	(1,051)	2,552	(2,238)
Income tax	Income tax benefit (expense)	(647)	432	(883)	877
Reclassification adjustments related to cash flow hedges, net of tax		$1,201	$(619)	$1,669	$(1,361)
Amortization of defined benefit plans:					
Prior service cost	Utilities - Operations and maintenance	$(31)	$—	$(62)	$—
	Non-regulated energy operations and maintenance	(32)	—	(64)	—
Actuarial gain (loss)	Utilities - Operations and maintenance	421	—	842	—
	Non-regulated energy operations and maintenance	274	—	548	—
		632	—	1,264	—
Income tax	Income tax benefit (expense)	(268)	—	(443)	—
Reclassification adjustments related to defined benefit plans,		$364	$—	$821	$—

net of tax

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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 Dec. 31, 2011	$(13,802)	$(19,076)	$(32,878)
Other comprehensive income (loss), net of tax	(166)	—	(166)
Balance as of March 31, 2012	(13,968)	(19,076)	(33,044)
Other comprehensive income (loss), net of tax	(608)	—	(608)
Ending Balance June 30, 2012	$(14,576)	$(19,076)	$(33,652)
Balance as of Dec. 31, 2012	$(15,713)	$(19,775)	$(35,488)
Other comprehensive income (loss), net of tax	(1,193)	457	(736)
Balance as of March 31, 2013	(16,906)	(19,318)	(36,224)
Other comprehensive income (loss), net of tax	5,079	364	5,443
Ending Balance June 30, 2013	$(11,827)	$(18,954)	$(30,781)

(8) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$1,608	$1,430	$3,216	$2,860
Interest cost	3,825	3,687	7,650	7,374
Expected return on plan assets	(4,654)	(4,084)	(9,308)	(8,168)
Prior service cost	16	22	32	44
Net loss (gain)	3,062	2,408	6,124	4,816
Net periodic benefit cost	$3,857	$3,463	$7,714	$6,926

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$419	$402	$838	$804
Interest cost	417	523	834	1,046
Expected return on plan assets	(20)	(19)	(40)	(38)
Prior service cost (benefit)	(125)	(125)	(250)	(250)
Net loss (gain)	121	222	242	444
Net periodic benefit cost	$812	$1,003	$1,624	$2,006

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$348	$246	$696	$492
Interest cost	332	331	664	662
Prior service cost	1	1	2	2
Net loss (gain)	198	202	396	404
Net periodic benefit cost	$879	$780	$1,758	$1,560

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	Contributions Made	Additional	
	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Contributions Anticipated for 2013	Contributions Anticipated for 2014
Defined Benefit Pension Plans	$—	$—	$12,500	$12,500
Non-pension Defined Benefit Postretirement Healthcare Plans	$784	$1,568	$1,568	$3,350
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$322	$644	$643	$1,463

(9) BUSINESS SEGMENT INFORMATION

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

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

Three Months Ended June 30, 2013	External Operating Revenue	Intercompany Operating Revenue	Income (Loss) from Continuing Operations
Utilities:			
Electric	$154,338	$3,694	$10,610
Gas	105,836	—	3,192
Non-regulated Energy:			
Power Generation	1,031	19,094	5,031
Coal Mining	6,807	7,511	1,973
Oil and Gas	11,814	—	(1,964)
Corporate activities [(a)]	—	—	11,679
Intercompany eliminations	—	(30,299)	(3)
Total	$279,826	$—	$30,518

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Three Months Ended June 30, 2012	External Operating Revenue	Intercompany Operating Revenue	Income (Loss) from Continuing Operations
Utilities:			
Electric	$144,560	$5,174	$14,159
Gas	70,386	—	1,159
Non-regulated Energy:			
Power Generation	759	17,975	3,926
Coal Mining	6,037	7,090	1,234
Oil and Gas [b]	20,621	—	(19,621)
Corporate activities [a]	—	—	(13,180)
Intercompany eliminations	—	(30,239)	—
Total	$242,363	$—	$(12,323)

Six Months Ended June 30, 2013	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$312,821	$7,841	$22,966
Gas	305,648	—	21,675
Non-regulated Energy:			
Power Generation	2,053	38,432	10,675
Coal Mining	12,817	15,084	3,038
Oil and Gas	27,158	—	(2,017)
Corporate [a]	—	—	17,378
Intercompany eliminations	—	(61,357)	—
Total	$660,497	$—	$73,715

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Six Months Ended June 30, 2012	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$300,693	$8,210	$22,905
Gas	250,908	—	16,366
Non-regulated Energy:			
Power Generation	1,937	36,424	10,840
Coal Mining	12,410	15,706	2,234
Oil and Gas [(b)]	42,266	—	(19,608)
Corporate [(a)(c)]	—	—	(9,789)
Intercompany eliminations	—	(60,340)	—
Total	$608,214	$—	$22,948

(a) Income (loss) from continuing operations includes a $12.2 million and a $17.1 million net after-tax non-cash mark-to-market gain on certain interest rate swaps for the three and six months ended June 30, 2013, respectively, and a $10.1 million and a $2.3 million net after-tax non-cash mark-to-market loss for the three and six months ended June 30, 2012, respectively, for those same interest rate swaps.

(b) Income (loss) from continuing operations includes a $17.3 million non-cash after-tax ceiling test impairment charge. See Note 14 for further information.

(c) Certain indirect corporate costs and inter-segment interest expense after-tax totaling $1.6 million for the six months ended June 30, 2012, were included in the Corporate activities in continuing operations and were not reclassified as discontinued operations.

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

Total Assets (net of inter-company eliminations) as of:	June 30, 2013	Dec. 31, 2012	June 30, 2012
Utilities:			
Electric [(a)]	$2,417,952	$2,387,458	$2,300,948
Gas	734,337	765,165	684,545
Non-regulated Energy:			
Power Generation [(a)]	108,515	119,170	122,856
Coal Mining	82,553	83,810	90,021
Oil and Gas	256,855	258,460	416,617
Corporate activities	146,302	115,408	159,293
Total assets	$3,746,514	$3,729,471	$3,774,280

(a) The PPA pertaining to the portion of the Pueblo Airport Generation Station owned by Colorado IPP that 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.

(10) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 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 in crude oil and natural gas reserves and production and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt including our 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 June 30, 2013, our credit exposure included a $0.6 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 (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 11.

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 (Loss).

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

	June 30, 2013		Dec. 31, 2012		June 30, 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)]	520,500	10,712,500	528,000	8,215,500	672,000	9,020,500
Maximum terms in years [(b)]	0.50	0.08	1.00	0.75	1.50	1.25
Derivative assets, current	$610	$293	$1,405	$1,831	$2,483	$4,386
Derivative assets, non-current	$—	$—	$297	$170	$1,316	$255
Derivative liabilities, current	$130	$276	$847	$507	$456	$452
Derivative liabilities, non-current	$—	$—	$—	$—	$981	$331
Pre-tax accumulated other comprehensive income (loss)	$827	$1,415	$206	$873	$1,727	$3,305
Cash collateral receivable (payable) included in derivatives	$(142)	$(1,419)	$786	$620	$613	$553
Cash collateral included in other assets or other liabilities	$(149)	$(1,007)	$1,078	$709	$267	$51

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

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

Based on market prices at June 30, 2013, a $0.7 million gain 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, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with state commission guidelines. Accordingly, the hedging activity is recognized in the Condensed Consolidated Statements of Income (Loss) or the Condensed Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

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

	June 30, 2013		Dec. 31, 2012		June 30, 2012	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	13,330,000	77	15,350,000	83	12,440,000	78
Natural gas options purchased	2,850,000	5	2,430,000	2	2,840,000	9
Natural gas basis swaps purchased	10,650,000	66	12,020,000	72	7,270,000	78

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

	June 30, 2013	Dec. 31, 2012	June 30, 2012
Derivative assets, current	$—	$—	$9,726
Derivative assets, non-current	$—	$43	$199
Derivative liabilities, non-current	$—	$—	$6,453
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$8,450	$9,596	$13,691
Cash collateral receivable (payable) included in derivatives	$7,203	$8,576	$15,925
Cash collateral included in Other current assets or liabilities	$2,938	$4,354	$—
Option premiums and commissions included in derivatives	$1,247	$1,063	$1,238

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:

	June 30, 2013		Dec. 31, 2012		June 30, 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	3.50	0.50	4.00	1.00	4.50	1.50
Derivative liabilities, current	$6,965	$61,899	$7,039	$88,148	$6,766	$78,001
Derivative liabilities, non-current	$12,384	$—	$16,941	$—	$18,976	$15,336
Pre-tax accumulated other comprehensive income (loss)	$(19,349)	$—	$(23,980)	$—	$(25,742)	$—
Pre-tax gain (loss)	$—	$26,249	$—	$1,882	$—	$(3,507)
Cash collateral receivable (payable) included in derivatives	$—	$5,960	$—	$5,960	$—	$6,160

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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 5.5 years and de-designated swaps totaling $150.0 million notional terminate in 15.5 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 June 30, 2013.

Based on June 30, 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.

(11) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. 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 can include calls and puts. Fair value was derived using quoted prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through third party sources and therefore support Level 2 disclosure.

- The commodity basis swaps for our Oil and Gas segment are valued 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 Segments:

- The commodity contracts for our Utilities Segments, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third party market participant because these instruments are not traded on an exchange.

Corporate Activities:

- The interest rate swaps are valued using the market approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting 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 gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis (in thousands):

	As of June 30, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$45	$—	$(6)	$39
Basis Swaps -- Oil	—	1,109	—	(538)	571
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,882	—	(1,589)	293
Commodity derivatives — Utilities	—	1,378	—	(1,378)	—
Cash equivalents [(a)]	30,633	—	—	—	30,633
Total	$30,633	$4,414	$—	$(3,511)	$31,536
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$181	$—	$(98)	$83
Basis Swaps -- Oil	—	350	—	(303)	47
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	445	—	(169)	276
Commodity derivatives — Utilities	—	8,581	—	(8,581)	—
Interest rate swaps	—	87,208	—	(5,960)	81,248
Total	$—	$96,765	$—	$(15,111)	$81,654

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(a) Level 1 assets and liabilities are described in Note 12.

	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 12.

(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 June 30, 2012				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$1,014	$—	$—	$1,014
Basis Swaps -- Oil	—	2,785	—	—	2,785
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	4,641	—	—	4,641
Commodity derivatives — Utilities	—	(6,024)	24 [(b)]	15,925	9,925
Cash equivalents [(a)]	44,882	—	—	—	44,882
Total	$44,882	$2,416	$24	$15,925	$63,247
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$901	$—	$457	$1,358
Basis Swaps -- Oil	—	(76)	—	156	80
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	230	—	553	783
Commodity derivatives — Utilities	—	6,453	—	—	6,453
Interest rate swaps	—	125,239	—	(6,160)	119,079
Total	$—	$132,747	$—	$(4,994)	$127,753

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(a) Level 1 assets and liabilities are described in Note 12.

(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, however, the amounts do not include net cash collateral on deposit in margin accounts at June 30, 2013, Dec. 31, 2012, and June 30, 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 10.

The following tables present the fair value and balance sheet classification of our derivative instruments (in thousands):
As of June 30, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,225	$—
Commodity derivatives	Derivative assets — non-current	1,651	—
Commodity derivatives	Derivative liabilities — current	—	889
Commodity derivatives	Derivative liabilities — non-current	—	41
Interest rate swaps	Derivative liabilities — current	—	6,965
Interest rate swaps	Derivative liabilities — non-current	—	12,384
Total derivatives designated as hedges		$2,876	$20,279
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$160	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	1,884
Commodity derivatives	Derivative liabilities — non-current	—	5,365
Interest rate swaps	Derivative liabilities — current	—	67,859
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$160	$75,108

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 June 30, 2012

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$6,869	$—
Commodity derivatives	Derivative assets — non-current	1,571	—
Commodity derivatives	Derivative liabilities — current	—	1,304
Commodity derivatives	Derivative liabilities — non-current	—	2,082
Interest rate swaps	Derivative liabilities — current	—	6,766
Interest rate swaps	Derivative liabilities — non-current	—	18,976
Total derivatives designated as hedges		$8,440	$29,128
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$6,199
Commodity derivatives	Derivative assets — non-current	—	(199)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	6,453
Interest rate swaps	Derivative liabilities — current	—	78,001
Interest rate swaps	Derivative liabilities — non-current	—	21,496
Total derivatives not designated as hedges		$—	$111,950

Derivatives Offsetting

It is our policy to offset in our Condensed Consolidated Balance Sheets contracts which provide for legally enforceable netting of our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross basis to the net, 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 June 30, 2013, Dec. 31, 2012, and June 30, 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 on our Condensed Consolidated Balance Sheets was as follows:

	As of June 30, 2013			
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
	(in thousands)			
Subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$538	$—	$(538)	$—
Oil and Gas - Crude Options	6	—	(6)	—
Oil and Gas - Natural Gas Basis Swaps	1,589	—	(1,589)	—
Utilities	1,378	(1,378)	—	—
Total derivative assets subject to a master netting agreement or similar arrangement	3,511	(1,378)	(2,133)	—
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	571	—	—	571
Oil and Gas - Crude Options	39	—	—	39
Oil and Gas - Natural Gas Basis Swaps	293	—	—	293
Utilities	—	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	903	—	—	903
Total derivative assets	$4,414	$(1,378)	$(2,133)	$903

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Derivative Liabilities	As of June 30, 2013 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
	(in thousands)			
Subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$303	$—	$(303)	$—
Oil and Gas - Crude Options	98	—	(98)	—
Oil and Gas - Natural Gas Basis Swaps	169	—	(169)	—
Utilities	8,581	(1,378)	(7,203)	—
Interest Rate Swaps	—	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	9,151	(1,378)	(7,773)	—
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	47	—	—	47
Oil and Gas - Crude Options	82	—	—	82
Oil and Gas - Natural Gas Basis Swaps	277	—	—	277
Utilities	—	—	—	—
Interest Rate Swaps	87,208	—	(5,960)	81,248
Total derivative liabilities not subject to a master netting agreement or similar arrangement	87,614	—	(5,960)	81,654
Total derivative liabilities	$96,765	$(1,378)	$(13,733)	$81,654

Derivative Assets	As of Dec. 31, 2012 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
	(in thousands)			
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	As of Dec. 31, 2012 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
	(in thousands)			
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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Derivative Assets	As of June 30, 2012 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
	(in thousands)			
Subject to master netting agreements or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$—	$—	$—	$—
Oil and Gas - Crude Options	343	—	—	343
Oil and Gas - Natural Gas Basis Swaps	—	—	—	—
Utilities	(6,000)	—	15,925	9,925
Total derivative assets subject to a master netting agreement or similar arrangement	(5,657)	—	15,925	10,268
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	2,785	—	—	2,785
Oil and Gas - Crude Options	671	—	—	671
Oil and Gas - Natural Gas Basis Swaps	4,641	—	—	4,641
Utilities	—	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	8,097	—	—	8,097
Total derivative assets	$2,440	$—	$15,925	$18,365

Derivative Liabilities	As of June 30, 2012 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
	(in thousands)			
Subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	$156	$—	$(156)	$—
Oil and Gas - Crude Options	457	—	(457)	—
Oil and Gas - Natural Gas Basis Swaps	553	—	(553)	—
Utilities	6,453	—	—	6,453
Interest Rate Swaps	—	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	7,619	—	(1,166)	6,453
Not subject to a master netting agreement or similar arrangement:				
Commodity derivative:				
Oil and Gas - Crude Basis Swaps	80	—	—	80
Oil and Gas - Crude Options	1,358	—	—	1,358
Oil and Gas - Natural Gas Basis Swaps	782	—	—	782
Utilities	—	—	—	—
Interest Rate Swaps	125,239	—	(6,160)	119,079
Total derivative liabilities not subject to a master netting agreement or similar arrangement	127,459	—	(6,160)	121,299
Total derivative liabilities	$135,078	$—	$(7,326)	$127,752

Derivative assets and derivative liabilities and collateral held by counterparty on our Condensed Consolidated Balance Sheets were (in thousands):

		As of June 30, 2013		
			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	903	—	903
Utilities	Counterparty A	—	—	—
		$903	$—	$903

		As of June 30, 2013		
			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	$—	$(1,156)	$(1,156)
Oil and Gas	Counterparty B	406	—	406
Utilities	Counterparty A	—	(2,938)	(2,938)
Interest Rate Swap	Counterparty D	3,727	—	3,727
Interest Rate Swap	Counterparty E	21,318	—	21,318
Interest Rate Swap	Counterparty F	10,232	—	10,232
Interest Rate Swap	Counterparty G	20,497	—	20,497
Interest Rate Swap	Counterparty H	9,782	—	9,782
Interest Rate Swap	Counterparty I	15,692	—	15,692
		$81,654	$(4,094)	$77,560

		As of Dec. 31, 2012		
			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

		As of Dec. 31, 2012		
			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	$—	$(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

Contract Type		As of June 30, 2012 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	$343	$—	$343
Oil and Gas	Counterparty B	8,097	—	8,097
Utilities	Counterparty A	9,925	—	9,925
		$18,365	$—	$18,365

Contract Type		As of June 30, 2012 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	$—	$(318)	$(318)
Oil and Gas	Counterparty B	2,220	—	2,220
Utilities	Counterparty A	6,453	—	6,453
Interest Rate Swap	Counterparty D	4,915	—	4,915
Interest Rate Swap	Counterparty E	31,491	—	31,491
Interest Rate Swap	Counterparty F	13,472	—	13,472
Interest Rate Swap	Counterparty G	27,153	—	27,153
Interest Rate Swap	Counterparty H	24,070	—	24,070
Interest Rate Swap	Counterparty I	17,978	—	17,978
		$127,752	$(318)	$127,434

A description of our derivative activities is included in Note 10. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income (Loss).

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

Three Months Ended June 30, 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	$1,067	Interest expense	$(1,820)		$—
Commodity derivatives	4,985	Revenue	(28)		—
Total	$6,052		$(1,848)		$—

Three Months Ended June 30, 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	$(2,251)	Interest expense	$(1,843)		$—
Commodity derivatives	2,429	Revenue	2,894		—
Total	$178		$1,051		$—

Six Months Ended June 30, 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	$1,048	Interest expense	$(3,616)		$—
Commodity derivatives	2,226	Revenue	1,064		—
Total	$3,274		$(2,552)		$—

Six Months Ended June 30, 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	$(3,013)	Interest expense	$(3,665)		$—
Commodity derivatives	3,712	Revenue	5,903		—
Total	$699		$2,238		$—

Derivatives Not Designated as Hedge Instruments

The impacts of derivative instruments not designated as hedge instruments on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2013 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2013 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$18,793	$26,249
Interest rate swaps - realized	Interest expense	(3,329)	(6,756)
		$15,464	$19,493

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$(15,552)	$(3,507)
Interest rate swaps - realized	Interest expense	(3,242)	(6,447)
		$(18,794)	$(9,954)

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	June 30, 2013		Dec. 31, 2012		June 30, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$30,633	$30,633	$15,462	$15,462	$40,110	$40,110
Restricted cash and equivalents [a]	$7,279	$7,279	$7,916	$7,916	$4,772	$4,772
Notes payable [a]	$100,000	$100,000	$277,000	$277,000	$225,000	$225,000
Long-term debt, including current maturities [b]	$1,214,066	$1,323,543	$1,042,850	$1,231,559	$1,272,481	$1,460,723

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(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.

(13) 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 2013:

- Cheyenne Light renewed and received FERC approval for an agreement with Basin Electric whereby Cheyenne Light will receive 40 megawatts of capacity and energy from Basin Electric through Sept. 30, 2014.

- Cheyenne Light renewed and received FERC approval for an agreement with Basin Electric whereby Cheyenne Light will provide 40 megawatts of capacity and energy to Basin Electric through Sept. 30, 2014.

Purchase and Sale Agreement

On May 6, 2013, Black Hills Wyoming entered into an agreement to sell its 40 megawatt CTII natural gas-fired generating unit to the City of Gillette, Wyo. for approximately $22.0 million, subject to closing adjustments. The sale is expected to close in August 2014 upon the expiration of an existing power sales agreement under which Black Hills Wyoming sells the output of the CTII to Cheyenne Light. The sale is subject to FERC approval and certain other requirements included in the contract.

Other Commitments

Construction of Cheyenne Prairie, a 132 megawatt natural gas-fired electric generating facility jointly owned 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 June 30, 2013, committed contracts for equipment purchases and for construction were 62 percent and 22 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 operations.

Sale of Enserco Energy Inc.

After the sale of Enserco, our Energy Marketing segment, on Feb. 29, 2012 and pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments, which we disputed. The buyer filed a petition in the Colorado District Court for the City and County of Denver, Colo., seeking an order compelling arbitration on all of the disputed claims. Following a hearing in July 2013, the court indicated it would enter an order remanding all but one of the disputed adjustment claims to arbitration. Upon entry of the final order, we will proceed as directed. The decision on this petition does not alter our evaluation of the merits of the adjustment claims.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of June 30, 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 June 30, 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 June 30, 2013, the restricted net assets at our Utilities Group were approximately $187.4 million.

- As required by a 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 completed in 2012. The guarantee expired March 29, 2013, upon fulfillment of all contractual obligations.

We had a guarantee of $7.5 million to Cross Timbers Energy Services for the performance and payment obligation of Black Hills Utility Holdings for natural gas supply purchases which expired on June 30, 2013 and was converted to a letter of credit for $5.0 million as a replacement to this guarantee.

(14) IMPAIRMENT OF LONG-LIVED ASSETS

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

As a result of continued low commodity prices during the second quarter of 2012, we recorded a $26.9 million non-cash impairment of oil and gas assets included in our Oil and Gas segment as of June 30, 2012. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead; for crude oil, the average NYMEX price was $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead.

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 202,000 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 532,000 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. Significant earnings variances can be expected between the Gas Utilities segment’s peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2013 and 2012, and our financial condition as of June 30, 2013, Dec. 31, 2012, and June 30, 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 85.

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 June 30, 2013 Compared to Three Months Ended June 30, 2012. Income from continuing operations for the three months ended June 30, 2013 was $30.5 million, or $0.69 per share, compared to Loss from continuing operations of $12.3 million, or $0.28 per share, reported for the same period in 2012. The 2013 Income from continuing operations included a $12.2 million after-tax non-cash unrealized mark-to-market gain on certain interest rate swaps. The 2012 Loss from continuing operations included a $10.1 million after-tax non-cash unrealized mark-to-market loss on the same interest rate swaps and a non-cash after-tax ceiling test impairment of $17.3 million relating to our Oil and Gas segment.

Net income for the three months ended June 30, 2013 was $30.5 million, or $0.69 per share, compared to Net loss of $13.5 million, or $0.31 per share, for the same period in 2012. Net income (loss) for the three months ended June 30, 2013 and 2012 includes the same significant items discussed above.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Income from continuing operations for the six months ended June 30, 2013 was $73.7 million, or $1.66 per share, compared to Income from continuing operations of $22.9 million, or $0.52 per share, reported for the same period in 2012. The 2013 Income from continuing operations included a $17.1 million after-tax non-cash unrealized mark-to-market gain on certain interest rate swaps. The 2012 Income from continuing operations included a $2.3 million after-tax non-cash unrealized mark-to-market loss on the same interest rate swaps, a non-cash after-tax ceiling test impairment of $17.3 million 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 six months ended June 30, 2013 was $73.7 million, or $1.66 per share, compared to Net income of $16.3 million, or $0.37 per share, for the same period in 2012. Net income for the six months ended June 30, 2013 and 2012 includes the same significant items discussed above.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
	(in thousands)					
Revenue						
Utilities	$263,868	$220,120	$43,748	$626,310	$559,811	$66,499
Non-regulated Energy	46,257	52,482	(6,225)	95,544	108,743	(13,199)
Intercompany eliminations	(30,299)	(30,239)	(60)	(61,357)	(60,340)	(1,017)
	$279,826	$242,363	$37,463	$660,497	$608,214	$52,283
Net income (loss)						
Electric Utilities	$10,610	$14,159	$(3,549)	$22,966	$22,905	$61
Gas Utilities	3,192	1,159	2,033	21,675	16,366	5,309
Utilities	13,802	15,318	(1,516)	44,641	39,271	5,370
Power Generation	5,031	3,926	1,105	10,675	10,840	(165)
Coal Mining	1,973	1,234	739	3,038	2,234	804
Oil and Gas [(a)]	(1,964)	(19,621)	17,657	(2,017)	(19,608)	17,591
Non-regulated Energy	5,040	(14,461)	19,501	11,696	(6,534)	18,230
Corporate activities and eliminations [(b)(c)]	11,676	(13,180)	24,856	17,378	(9,789)	27,167
Income (loss) from continuing operations	30,518	(12,323)	42,841	73,715	22,948	50,767
Income (loss) from discontinued operations, net of tax	—	(1,160)	1,160	—	(6,644)	6,644
Net income (loss)	$30,518	$(13,483)	$44,001	$73,715	$16,304	$57,411

(a) Net income (loss) for 2012 includes a $17.3 million non-cash after-tax ceiling test impairment. See Note 14 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Corporate activities include a $12.2 million and a $17.1 million net after-tax non-cash mark-to-market gain on certain interest rate swaps for the three and six months ended June 30, 2013, respectively, and a $10.1 million and a $2.3 million net after-tax non-cash mark-to-market loss for the three and six months ended June 30, 2012, respectively, for those same interest rate swaps.

(c) Certain indirect corporate costs and inter-segment interest expenses after-tax totaling $1.6 million for the six months ended June 30, 2012 were included in the Corporate activities in continuing operations and were not reclassified as discontinued operations.

Overview of Business Segments and Corporate Activity

Utilities Group

- Gas Utilities results were favorably impacted by colder weather. Heating degree days were 72 percent and 37 percent higher for the three and six months ended June 30, 2013, respectively, compared to the same periods in 2012. Heating degree days for the three and six months ended June 30, 2013 were 24 percent and 9 percent higher than normal, respectively, compared to 31 percent and 22 percent lower than normal for the same periods in 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. Project to date, we have expended approximately $87.6 million. The project is on schedule to be placed into service in the fourth quarter of 2014.

- 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 typical AFUDC. 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. The Electric Utilities recorded additional gross margins of approximately $1.7 million and $2.2 million for the three and six months ended June 30, 2013, respectively, relating to these riders.

- On June 16, 2013, Black Hills Power implemented interim rates, subject to refund, relating to the rate request filed with the SDPUC on Dec. 17, 2012, seeking a $13.7 million increase in annual electric revenues. A hearing with the SDPUC is scheduled in the fourth quarter of 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 total 29 megawatts and were placed in service in the 1940s. A hearing with the CPUC is scheduled in November 2013 regarding the resource plan and the two CPCN’s.

- On April 23, 2013, Colorado Electric issued a request for proposals for up to 30 megawatts of wind energy for its electric system. Adding another 30 megawatts of wind generation will assist Colorado Electric towards meeting Colorado’s renewable energy standard mandated by state law. Bids have been received, an independent evaluation has been completed and bid results have been submitted to the commission. Our Power Generation segment elected to bid into this request for proposal. A hearing with the CPUC is scheduled for September 2013 with an initial decision anticipated in October 2013.

- Gas Utilities continued its efforts to acquire small municipal gas distribution systems adjacent to our existing gas utility service territories. Three small gas systems have been acquired in 2013, adding approximately 800 retail and two high-volume industrial customers.

Non-regulated Energy Group

- Black Hills Wyoming entered into an agreement to sell its 40 megawatt CTII natural gas-fired generating unit to the City of Gillette, Wyo. for approximately $22 million, subject to closing adjustments. The sale is expected to close in August 2014 upon the expiration of an existing power sales agreement. The sale is subject to FERC approval and certain other requirements included in the contract.

- Oil and Gas reported a 34 percent and 31 percent reduction in total volumes sold for the three and six months ended June 30, 2013, respectively, reflecting the 2012 sale of the Williston Basin oil and gas assets. Results benefited from a 24 percent and 19 percent increase in average hedge price received for crude oil during the three and six months ended June 30, 2013, respectively, compared to the same period in 2012, partially offset by a 25 percent and 22 percent decrease in average hedge price received for natural gas for those same periods.

- Oil and Gas drilled two horizontal wells in the Mancos Shale formation in the Piceance Basin. We expect both wells to be completed and producing prior to year-end. The wells are part of a transaction in which we will earn approximately 20,000 net acres of Mancos Shale leasehold in the Piceance Basin in exchange for drilling and completing the two wells.

- In the second quarter of 2012, our Oil and Gas segment recorded a $26.9 million non-cash ceiling test impairment loss as a result of continued low commodity prices.

Corporate Activities

- On July 24, 2013, S&P raised our corporate credit rating to BBB from BBB-, with a stable outlook. They also raised our senior unsecured rating to BBB from BBB-. On May 10, Fitch Ratings raised our Issuer Default Rating to BBB from BBB-, with a positive outlook.

- On June 21, 2013, we entered into a new $275 million term loan expiring on June 19, 2015. This new term loan replaced the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on Sept. 30, 2013, and $25 million in short-term borrowing under our Revolving Credit Facility.

- Consolidated interest expense decreased by approximately $4.4 million and $10.6 million for the three and six months ended June 30, 2013, respectively, due primarily to the repayment of approximately $225 million of debt in 2012.

- We recognized a non-cash unrealized mark-to-market gain (loss) related to certain interest rate swaps of $26.2 million and $(3.5) million for the six months ended June 30, 2013 and 2012, respectively.

Operating Results

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

Utilities Group

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

Electric Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
	(in thousands)					
Revenue — electric	$151,775	$144,985	$6,790	$302,148	$291,266	$10,882
Revenue — gas	6,257	4,749	1,508	18,514	17,637	877
Total revenue	158,032	149,734	8,298	320,662	308,903	11,759
Fuel, purchased power and cost of gas — electric	67,349	59,523	7,826	133,038	125,121	7,917
Purchased gas — gas	2,515	1,923	592	8,953	10,041	(1,088)
Total fuel, purchased power and cost of gas	69,864	61,446	8,418	141,991	135,162	6,829
Gross margin — electric	84,426	85,462	(1,036)	169,110	166,145	2,965
Gross margin — gas	3,742	2,826	916	9,561	7,596	1,965
Total gross margin	88,168	88,288	(120)	178,671	173,741	4,930
Operations and maintenance	39,383	36,866	2,517	78,218	76,096	2,122
Depreciation and amortization	19,665	18,695	970	38,826	37,627	1,199
Total operating expenses	59,048	55,561	3,487	117,044	113,723	3,321
Operating income	29,120	32,727	(3,607)	61,627	60,018	1,609
Interest expense, net	(13,810)	(12,322)	(1,488)	(28,207)	(25,542)	(2,665)
Other income (expense), net	173	291	(118)	458	1,009	(551)
Income tax benefit (expense)	(4,873)	(6,537)	1,664	(10,912)	(12,580)	1,668
Income (loss) from continuing operations	$10,610	$14,159	$(3,549)	$22,966	$22,905	$61

Revenue - Electric (in thousands)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Residential:				
Black Hills Power	$13,535	$12,633	$29,977	$28,109
Cheyenne Light	8,307	7,022	17,637	15,492
Colorado Electric	21,829	21,042	45,950	43,658
Total Residential	43,671	40,697	93,564	87,259
Commercial:				
Black Hills Power	18,913	18,804	36,397	35,612
Cheyenne Light	14,476	15,386	27,243	29,343
Colorado Electric	21,663	21,570	42,814	40,697
Total Commercial	55,052	55,760	106,454	105,652
Industrial:				
Black Hills Power	7,210	7,063	13,220	13,083
Cheyenne Light	5,344	3,243	10,199	6,312
Colorado Electric	9,647	9,981	19,284	19,213
Total Industrial	22,201	20,287	42,703	38,608
Municipal:				
Black Hills Power	847	887	1,561	1,585
Cheyenne Light	490	472	948	898
Colorado Electric	3,492	3,948	6,039	6,612
Total Municipal	4,829	5,307	8,548	9,095
Total Retail Revenue - Electric	125,753	122,051	251,269	240,614
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	4,926	4,370	10,693	9,275
Off-system Wholesale:				
Black Hills Power	7,849	6,459	14,099	17,732
Cheyenne Light	2,094	1,967	4,776	4,480
Colorado Electric	2,133	177	3,240	410
Total Off-system Wholesale	12,076	8,603	22,115	22,622
Other Revenue:				
Black Hills Power	7,552	8,156	14,702	15,246
Cheyenne Light	482	427	1,048	1,039
Colorado Electric	986	1,378	2,321	2,470
Total Other Revenue	9,020	9,961	18,071	18,755
Total Revenue - Electric	$151,775	$144,985	$302,148	$291,266

Quantities Generated and Purchased (in MWh)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Generated —				
Coal-fired:				
Black Hills Power [(a)]	450,097	369,049	877,112	868,841
Cheyenne Light	155,384	154,324	327,696	281,477
Colorado Electric [(b)]	—	58,585	—	115,892
Total Coal-fired	605,481	581,958	1,204,808	1,266,210
Gas, Oil and Wind:				
Black Hills Power	4,558	6,216	7,678	6,579
Cheyenne Light	—	—	—	—
Colorado Electric [(c)]	119,369	19,948	161,596	21,580
Total Gas, Oil and Wind	123,927	26,164	169,274	28,159
Total Generated:				
Black Hills Power	454,655	375,265	884,790	875,420
Cheyenne Light	155,384	154,324	327,696	281,477
Colorado Electric	119,369	78,533	161,596	137,472
Total Generated	729,408	608,122	1,374,082	1,294,369
Purchased —				
Black Hills Power	349,183	432,723	737,382	947,257
Cheyenne Light	205,027	181,408	406,872	413,027
Colorado Electric	412,037	409,242	867,175	810,369
Total Purchased	966,247	1,023,373	2,011,429	2,170,653
Total Generated and Purchased:				
Black Hills Power	803,838	807,988	1,622,172	1,822,677
Cheyenne Light	360,411	335,732	734,568	694,504
Colorado Electric	531,406	487,775	1,028,771	947,841
Total Generated and Purchased	1,695,655	1,631,495	3,385,511	3,465,022

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(a) Megawatt hours generated for the three and six months ended June 30, 2013, were impacted by the suspension of operations at Ben French as of Aug. 31, 2012, while megawatt hours generated for the three months ended June 30, 2012 were impacted by plant outages at Neil Simpson II and Wygen III.

(b) Decrease was primarily due to the suspension of operations at W.N. Clark as of Dec. 31, 2012.

(c) Increase was primarily due to the addition of energy from the Busch Ranch wind project, which was placed into commercial operation in the fourth quarter of 2012 and 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 as of Dec. 31, 2012 and a decrease in available economy energy.

Quantity Sold (in MWh)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Residential:				
Black Hills Power	113,525	106,557	274,495	256,985
Cheyenne Light	60,669	56,440	136,125	128,277
Colorado Electric	140,755	136,677	296,191	290,729
Total Residential	314,949	299,674	706,811	675,991
Commercial:				
Black Hills Power	174,763	181,281	350,380	351,374
Cheyenne Light	132,214	158,346	261,643	308,285
Colorado Electric	180,340	184,734	351,045	350,125
Total Commercial	487,317	524,361	963,068	1,009,784
Industrial:				
Black Hills Power	105,856	115,024	197,488	210,759
Cheyenne Light	65,716	44,155	135,668	88,929
Colorado Electric	92,867	97,192	171,416	178,434
Total Industrial	264,439	256,371	504,572	478,122
Municipal:				
Black Hills Power	8,147	8,843	15,930	16,411
Cheyenne Light	2,143	2,128	4,738	4,710
Colorado Electric	29,049	35,019	47,095	60,188
Total Municipal	39,339	45,990	67,763	81,309
Total Retail Quantity Sold	1,106,044	1,126,396	2,242,214	2,245,206
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	77,653	72,006	181,437	161,054
Off-system Wholesale:				
Black Hills Power	277,840	295,149	516,287	753,379
Cheyenne Light	61,514	53,911	131,822	120,620
Colorado Electric	38,238	6,063	70,015	8,671
Total Off-system Wholesale	377,592	355,123	718,124	882,670
Total Quantity Sold:				
Black Hills Power	757,784	778,860	1,536,017	1,749,962
Cheyenne Light	322,256	314,980	669,996	650,821
Colorado Electric	481,249	459,685	935,762	888,147
Total Quantity Sold	1,561,289	1,553,525	3,141,775	3,288,930
Losses and Company Use:				
Black Hills Power	46,054	29,128	86,155	72,715
Cheyenne Light	38,155	20,752	64,572	43,682
Colorado Electric	50,157	28,090	93,009	59,695
Total Losses and Company Use	134,366	77,970	243,736	176,092

Total Quantity Sold	1,695,655	1,631,495	3,385,511	3,465,022

Degree Days	Three Months Ended June 30, 2013 Actual	Variance from 30-Year Average		2012 Actual	Variance from 30-Year Average	
Heating Degree Days:						
Black Hills Power	1,227	43	%	748	(27	)%
Cheyenne Light	1,321	11	%	841	(29	)%
Colorado Electric	752	(1	)%	405	(36	)%
Cooling Degree Days:						
Black Hills Power	78	(27	)%	206	108	%
Cheyenne Light	123	141	%	138	176	%
Colorado Electric	376	66	%	423	102	%

Degree Days	Six Months Ended June 30, 2013 Actual	Variance from 30-Year Average		2012 Actual	Variance from 30-Year Average	
Heating Degree Days:						
Black Hills Power	4,437	9	%	3,459	(18	)%
Cheyenne Light	4,483	6	%	3,602	(14	)%
Colorado Electric	3,502	4	%	2,699	(18	)%
Cooling Degree Days:						
Black Hills Power	78	(27	)%	206	108	%
Cheyenne Light	123	141	%	138	176	%
Colorado Electric	376	66	%	423	102	%

Electric Utilities Power Plant Availability	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
Coal-fired plants	96.0	%	81.0	% (a)	96.4	%	86.0	% (a)
Other plants	95.5	%	96.4	%	97.1	%	95.7	%
Total availability	95.7	%	88.8	%	96.7	%	90.9	%

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(a) Three and six months ended June 30, 2012 reflects an unplanned outage due to a transformer failure and a planned outage at Neil Simpson II. Six months ended June 30, 2012 also includes a planned and extended overhaul at Wygen II.

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenue - Gas (in thousands):				
Residential	$4,033	$2,955	$11,565	$10,585
Commercial	1,522	1,209	5,130	5,019
Industrial	505	397	1,403	1,634
Other Sales Revenue	197	188	416	399
Total Revenue - Gas	$6,257	$4,749	$18,514	$17,637
Gross Margin (in thousands):				
Residential	$2,674	$2,002	$6,634	$5,228
Commercial	748	551	2,240	1,724
Industrial	123	85	271	249
Other Gross Margin	197	188	416	395
Total Gross Margin	$3,742	$2,826	$9,561	$7,596
Volumes Sold (Dth):				
Residential	492,261	315,571	1,585,261	1,285,249
Commercial	278,914	217,847	904,851	798,787
Industrial	137,212	109,803	364,159	346,943
Total Volumes Sold	908,387	643,221	2,854,271	2,430,979

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012: Income from continuing operations for the Electric Utilities was $10.6 million for the three months ended June 30, 2013, compared to $14.2 million for the three months ended June 30, 2012, as a result of:

Gross margin was comparable to the same period in the prior year reflecting a $1.6 million decrease related to lower electric retail megawatt hours sold and a $1.1 million decrease as a result of energy cost adjustments, partially offset by a $1.7 million increase related to the Cheyenne Prairie construction financing riders, a $0.6 million increase from transmission margins from increased pricing, and a $0.4 million increase in gas rate adjustments.

Operations and maintenance increased primarily due to an increase in property taxes and employee compensation and benefit costs, partially offset by reduced costs resulting from plant suspensions compared to the same period in the prior year.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net increased primarily due to an increase in debt balances 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 was comparable to the same period in the prior year.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012: Income from continuing operations for the Electric Utilities was $23.0 million for the six months ended June 30, 2013, compared to $22.9 million for the six months ended June 30, 2012, as a result of:

Gross margin increased primarily due to a $2.2 million increase related to the Cheyenne Prairie construction financing riders, a $1.4 million increase from transmission cost adjustments from increased pricing, a $1.1 million increase from electric rate adjustments, a $0.9 million increase in demand from colder weather, and a $1.0 million increase in gas rate adjustments, partially offset by a $0.3 million decrease related to lower electric retail volumes and a $1.1 million decrease as a result of energy cost adjustments.

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

Depreciation and amortization increased primarily due to an increased asset base.

Interest expense, net increased primarily due to an increase in debt balances 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 and an increased benefit for a repairs deduction taken for tax purposes and the flow through treatment of such tax benefit.

Gas Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
	(in thousands)					
Natural gas — regulated	$98,635	$64,033	$34,602	$290,586	$236,202	$54,384
Other — non-regulated services	7,201	6,353	848	15,062	14,706	356
Total revenue	105,836	70,386	35,450	305,648	250,908	54,740
Natural gas — regulated	53,143	25,424	27,719	173,523	133,540	39,983
Other — non-regulated services	3,517	3,020	497	7,234	6,889	345
Total cost of sales	56,660	28,444	28,216	180,757	140,429	40,328
Gross margin	49,176	41,942	7,234	124,891	110,479	14,412
Operations and maintenance	31,852	28,483	3,369	65,078	59,782	5,296
Depreciation and amortization	6,583	6,253	330	13,086	12,410	676
Total operating expenses	38,435	34,736	3,699	78,164	72,192	5,972
Operating income (loss)	10,741	7,206	3,535	46,727	38,287	8,440
Interest expense, net	(5,907)	(5,749)	(158)	(12,184)	(12,289)	105
Other income (expense), net	(5)	73	(78)	7	84	(77)
Income tax benefit (expense)	(1,637)	(371)	(1,266)	(12,875)	(9,716)	(3,159)
Income (loss) from continuing operations	$3,192	$1,159	$2,033	$21,675	$16,366	$5,309

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	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue (in thousands)	2013	2012	2013	2012
Residential:				
Colorado	$9,850	$7,321	$29,644	$29,339
Nebraska	22,932	13,538	71,784	54,462
Iowa	18,139	11,870	56,890	46,440
Kansas	12,620	7,762	38,385	29,183
Total Residential	63,541	40,491	196,703	159,424
Commercial:				
Colorado	1,778	1,433	5,438	5,627
Nebraska	7,098	3,918	23,345	18,018
Iowa	8,442	4,734	26,217	20,507
Kansas	4,052	1,994	12,841	8,729
Total Commercial	21,370	12,079	67,841	52,881
Industrial:				
Colorado	507	594	555	646
Nebraska	100	140	305	429
Iowa	709	449	1,454	1,194
Kansas	6,068	4,314	7,000	5,236
Total Industrial	7,384	5,497	9,314	7,505
Transportation:				
Colorado	227	157	628	503
Nebraska	2,395	1,672	7,111	5,471
Iowa	999	978	2,538	2,228
Kansas	1,453	1,161	3,502	3,029
Total Transportation	5,074	3,968	13,779	11,231
Other Sales Revenue:				
Colorado	22	21	(52)	50
Nebraska	626	517	1,240	1,092
Iowa	190	141	302	264
Kansas	428	1,319	1,459	3,755
Total Other Sales Revenue	1,266	1,998	2,949	5,161
Total Regulated Revenue	98,635	64,033	290,586	236,202
Non-regulated Services	7,201	6,353	15,062	14,706
Total Revenue	$105,836	$70,386	$305,648	$250,908

	Three Months Ended June 30,		Six Months Ended June 30,	
Gross Margin (in thousands)	2013	2012	2013	2012
Residential:				
Colorado	$3,884	$3,141	$10,122	$8,827
Nebraska	11,055	8,997	29,366	24,588
Iowa	9,397	8,328	22,986	20,523
Kansas	6,925	5,795	17,129	14,915
Total Residential	31,261	26,261	79,603	68,853
Commercial:				
Colorado	579	503	1,568	1,419
Nebraska	2,292	1,740	6,927	5,623
Iowa	2,592	2,036	7,044	5,833
Kansas	1,519	1,108	4,163	3,278
Total Commercial	6,982	5,387	19,702	16,153
Industrial:				
Colorado	158	172	188	202
Nebraska	31	44	85	105
Iowa	81	45	163	116
Kansas	750	772	974	994
Total Industrial	1,020	1,033	1,410	1,417
Transportation:				
Colorado	227	157	628	504
Nebraska	2,395	1,672	7,111	5,471
Iowa	999	978	2,538	2,228
Kansas	1,453	1,161	3,502	3,029
Total Transportation	5,074	3,968	13,779	11,232
Other Sales Margins:				
Colorado	22	21	(52)	50
Nebraska	626	518	1,240	1,093
Iowa	190	142	302	265
Kansas	318	1,279	1,079	3,600
Total Other Sales Margins	1,156	1,960	2,569	5,008
Total Regulated Gross Margin	45,493	38,609	117,063	102,663
Non-regulated Services	3,683	3,333	7,828	7,816
Total Gross Margin	$49,176	$41,942	$124,891	$110,479

	Three Months Ended June 30,		Six Months Ended June 30,	
Volumes Sold (in Dth)	2013	2012	2013	2012
Residential:				
Colorado	1,268,892	797,696	4,190,227	3,401,097
Nebraska	2,056,892	998,527	7,794,565	5,351,344
Iowa	1,732,786	854,889	7,023,152	5,006,355
Kansas	1,044,593	498,802	4,260,899	3,158,476
Total Residential	6,103,163	3,149,914	23,268,843	16,917,272
Commercial:				
Colorado	256,317	179,454	832,593	706,248
Nebraska	836,828	509,760	3,035,626	2,290,391
Iowa	1,164,878	669,018	3,970,551	2,896,813
Kansas	474,953	226,476	1,752,087	1,219,481
Total Commercial	2,732,976	1,584,708	9,590,857	7,112,933
Industrial:				
Colorado	127,124	140,017	136,861	150,569
Nebraska	13,585	24,801	44,265	65,702
Iowa	129,772	93,817	272,096	222,959
Kansas	1,222,845	1,280,464	1,411,666	1,469,361
Total Industrial	1,493,326	1,539,099	1,864,888	1,908,591
Total Volumes Sold	10,329,465	6,273,721	34,724,588	25,938,796
Transportation:				
Colorado	216,333	146,703	629,042	508,576
Nebraska	6,040,006	5,448,471	14,722,321	13,589,365
Iowa	4,790,583	4,492,459	10,469,740	9,679,955
Kansas	3,336,618	3,286,586	7,388,636	7,646,507
Total Transportation	14,383,540	13,374,219	33,209,739	31,424,403
Wholesale:				
Kansas	19,199	7,503	74,209	31,953
Total Other Volumes	19,199	7,503	74,209	31,953
Total Volumes and Transportation Sold	24,732,204	19,655,443	68,008,536	57,395,152

	Three Months Ended June 30,			
	2013		2012	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	972	5 %	552	(40)%
Nebraska	769	33 %	370	(36)%
Iowa	873	27 %	614	(21)%
Kansas [a]	636	42 %	291	(39)%
Combined [b]	842	24 %	490	(31)%

	Six Months Ended June 30,			
	2013		2012	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	3,844	4 %	2,902	(22)%
Nebraska	3,898	8 %	2,770	(23)%
Iowa	4,616	14 %	3,413	(20)%
Kansas [a]	3,186	9 %	2,331	(21)%
Combined [b]	4,148	9 %	3,026	(22)%

(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 June 30, 2013 Compared to the Three Months Ended June 30, 2012: Income from continuing operations for the Gas Utilities was $3.2 million for the three months ended June 30, 2013, compared to Income from continuing operations of $1.2 million for the three months ended June 30, 2012, as a result of:

Gross margin increased primarily due to higher residential consumption and transport volumes driven by 72 percent higher heating degree days than in the same period in the prior year. Heating degree days were 24 percent higher than normal for the period.

Operations and maintenance increased primarily due to an increase in employee compensation and benefit costs and uncollectible accounts compared to the same period in the prior year.

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

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

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

Income tax benefit (expense): The effective tax rate increased as a result of a favorable true-up adjustment that was recorded in 2012. Such adjustment had a pronounced impact in 2012 due to significantly lower pre-tax income.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012: Income from continuing operations for the Gas Utilities was $21.7 million for the six months ended June 30, 2013, compared to Income from continuing operations of $16.4 million for the six months ended June 30, 2012, as a result of:

Gross margin increased primarily due to higher residential consumption and transport volumes driven by 37 percent higher heating degree days compared to the same period in the prior year. Heating degree days were 9 percent higher than normal for the period.

Operations and maintenance increased primarily due to an increase in employee compensation and benefit costs and uncollectible accounts compared to the same period in the prior year.

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

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

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

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

Regulatory Matters — Utilities Group

The following summarizes our recent state and federal rate case and initial surcharge orders (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 was 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. Interim rates, subject to refund, were implemented 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 Cheyenne Prairie in lieu of the typical AFUDC. 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 June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
	(in thousands)					
Revenue	$20,125	$18,734	$1,391	$40,485	$38,361	$2,124
Operations and maintenance	8,161	7,566	595	15,952	14,698	1,254
Depreciation and amortization	1,313	1,116	197	2,539	2,230	309
Total operating expense	9,474	8,682	792	18,491	16,928	1,563
Operating income	10,651	10,052	599	21,994	21,433	561
Interest expense, net	(2,706)	(3,972)	1,266	(5,380)	(8,715)	3,335
Other (expense) income, net	(4)	9	(13)	(3)	14	(17)
Income tax (expense) benefit	(2,910)	(2,163)	(747)	(5,936)	(1,892)	(4,044)
Income (loss) from continuing operations	$5,031	$3,926	$1,105	$10,675	$10,840	$(165)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Contracted power plant fleet availability:				
Coal-fired plant	94.0 %	99.2 %	97.0 %	99.6 %
Natural gas-fired plants	99.2 %	98.9 %	98.9 %	99.2 %
Total availability	98.0 %	99.0 %	98.5 %	99.3 %

Results of Operations for Power Generation for the Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012: Income from continuing operations for the Power Generation segment was $5.0 million for the three months ended June 30, 2013, compared to Income from continuing operations of $3.9 million for the same period in 2012 as a result of:

Revenue increased primarily due to an increase in megawatt hours delivered at a higher price and increased contract pricing.

Operations and maintenance increased primarily due to increases in repairs and maintenance costs and property taxes.

Depreciation and amortization were 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.

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

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

Results of Operations for Power Generation for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012: Income from continuing operations for the Power Generation segment was $10.7 million for the six months ended June 30, 2013, compared to Income from continuing operations of $10.8 million for the same period in 2012 as a result of:

Revenue increased primarily due to an increase in megawatt hours delivered at a higher price, an increase in off-system sales and increased contract pricing.

Operations and maintenance increased primarily due to increases in property taxes, repairs and maintenance costs and in employee compensation and benefits.

Depreciation and amortization were 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 primarily due to lower debt balances.

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

Income tax (expense) benefit: The effective tax rate increased from the same period in the prior year primarily due to a benefit recognized for a state tax true-up that included certain research and development tax credits in 2012.

Coal Mining

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
	(in thousands)					
Revenue	$14,318	$13,127	$1,191	$27,901	$28,116	$(215)
Operations and maintenance	9,251	9,883	(632)	19,402	21,361	(1,959)
Depreciation, depletion and amortization	2,964	2,955	9	5,829	6,651	(822)
Total operating expenses	12,215	12,838	(623)	25,231	28,012	(2,781)
Operating income (loss)	2,103	289	1,814	2,670	104	2,566
Interest (expense) income, net	(179)	403	(582)	(310)	1,158	(1,468)
Other income, net	581	646	(65)	1,194	1,527	(333)
Income tax benefit (expense)	(532)	(104)	(428)	(516)	(555)	39
Income (loss) from continuing operations	$1,973	$1,234	$739	$3,038	$2,234	$804

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Tons of coal sold	1,079	983	2,132	2,086
Cubic yards of overburden moved	930	2,280	1,989	4,922

Results of Operations for Coal Mining for the Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012: Income from continuing operations for the Coal Mining segment was $2.0 million for the three months ended June 30, 2013, compared to Income from continuing operations of $1.2 million for the same period in 2012 as a result of:

Revenue increased primarily due to a 10 percent increase in tons sold primarily as a result of customer plant outages in the prior year that did not occur in the current year.

Operations and maintenance decreased primarily due to mining in areas with lower overburden, decreased fuel costs and headcount reductions.

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

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

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

Income tax benefit (expense): The primary factor impacting the effective tax rate was the estimated tax benefit produced by percentage depletion. Such tax benefit was essentially the same for both periods; however, its impact on the effective tax rate was not as pronounced when compared to 2012 due to the significantly greater pre-tax income generated in 2013.

Results of Operations for Coal Mining for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012: Income from continuing operations for the Coal Mining segment was $3.0 million for the six months ended June 30, 2013, compared to Income from continuing operations of $2.2 million for the same period in 2012 as a result of:

Revenue was comparable to the same period in the prior year, reflecting a 2 percent decrease in average price per ton partially offset by a 2 percent increase in tons sold as a result of customer outages that occurred in the prior year. 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 due to mining in areas with lower overburden, decreased fuel costs and headcount reductions.

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

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

Other income, net 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.

Oil and Gas

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
	(in thousands)					
Revenue	$11,814	$20,621	$(8,807)	$27,158	$42,266	$(15,108)
Operations and maintenance	9,995	10,338	(343)	20,250	21,172	(922)
Depreciation, depletion and amortization	5,214	13,033	(7,819)	10,581	22,356	(11,775)
Impairment of long-lived assets	—	26,868	(26,868)	—	26,868	(26,868)
Total operating expenses	15,209	50,239	(35,030)	30,831	70,396	(39,565)
Operating income (loss)	(3,395)	(29,618)	26,223	(3,673)	(28,130)	24,457
Interest income (expense), net	(54)	(1,165)	1,111	25	(2,770)	2,795
Other income (expense), net	81	87	(6)	4	116	(112)
Income tax benefit (expense)	1,404	11,075	(9,671)	1,627	11,176	(9,549)
Income (loss) from continuing operations	$(1,964)	$(19,621)	$17,657	$(2,017)	$(19,608)	$17,591

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Production:				
Bbls of oil sold	65,304	155,362	162,107	300,839
Mcf of natural gas sold	1,784,389	2,451,811	3,517,339	4,840,286
Gallons of NGL sold	895,720	837,626	1,841,534	1,652,211
Mcf equivalent sales	2,304,173	3,503,644	4,753,057	6,881,350

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Average price received: (a)				
Oil/Bbl	$95.15	$76.71	$91.71	$77.33
Gas/Mcf	$2.35	$3.12	$2.63	$3.36
NGL/gallon	$0.73	$0.74	$0.84	$0.84
Depletion expense/Mcfe	$1.82	$3.47	$1.80	$2.98

(a) Net of hedge settlement gains and losses.

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

	Three Months Ended June 30, 2013				Three Months Ended June 30, 2012			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.39	$0.40	$0.52	$2.31	$1.06	$0.19	$0.23	$1.48
Piceance	$0.80	$0.52	$0.27	$1.59	$0.52	$0.32	$0.10	$0.94
Powder River	$2.00	$—	$1.23	$3.23	$1.60	$—	$1.08	$2.68
Williston	$1.43	$—	$2.52	$3.95	$0.53	$—	$1.29	$1.82
All other properties	$0.65	$—	$(0.48)	$0.17	$1.59	$—	$0.18	$1.77
Total weighted average	$1.32	$0.27	$0.55	$2.14	$1.00	$0.13	$0.54	$1.67

	Six Months Ended June 30, 2013				Six Months Ended June 30, 2012			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.34	$0.37	$0.47	$2.18	$1.02	$0.25	$0.29	$1.56
Piceance	0.73	0.58	0.30	1.61	0.23	0.41	0.13	0.77
Powder River	1.62	—	1.24	2.86	1.49	—	1.20	2.69
Williston	0.94	—	1.34	2.28	0.61	—	1.27	1.88
All other properties	0.67	—	(0.08)	0.59	1.63	—	0.13	1.76
Total weighted average	$1.19	$0.25	$0.60	$2.04	$0.94	$0.17	$0.57	$1.68

Results of Operations for Oil and Gas for the Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012: Loss from continuing operations for the Oil and Gas segment was $2.0 million for the three months ended June 30, 2013, compared to Loss from continuing operations of $19.6 million for the same period in 2012 as a result of:

Revenue decreased primarily due to a 34 percent decrease in volumes sold as a result of our Williston Basin asset sale in 2012, and a 24 percent decrease in the average price received for natural gas sold, partially offset by a 25 percent increase in the average price received for crude oil sold.

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

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

Impairment of long-lived assets represented a write-down in the value of our natural gas and crude oil properties driven by low natural gas prices in 2012. The write-down reflected a 12 month average NYMEX gas price of $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead, and $95.67 per barrel, adjusted to $85.36 per barrel for crude oil at the wellhead.

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

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.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012: Loss from continuing operations for the Oil and Gas segment was $2.0 million for the six months ended June 30, 2013, compared to Loss from continuing operations of $19.6 million for the same period in 2012 as a result of:

Revenue decreased primarily due to a 31 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 a 21 percent decrease in the average price received for natural gas sold, partially offset by a 19 percent increase in the average price received for crude oil sold.

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

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

Impairment of long-lived assets represented a write-down in the value of our natural gas and crude oil properties driven by low natural gas prices in 2012. The write-down reflected a 12 month average NYMEX gas price of $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead and $95.67 per barrel, adjusted to $85.36 per barrel for crude oil at the wellhead.

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

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. In addition, 2013 has been favorably impacted by a net tax benefit from research and development tax credits including the retroactive effect of the full year 2012 estimated benefit.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012: Income from continuing operations for Corporate was $11.7 million for the three months ended June 30, 2013, compared to Loss from continuing operations of $13.2 million for the three months ended June 30, 2012. The variance from the prior year was primarily due to market interest rate changes creating unrealized, non-cash mark-to-market gains on certain interest rate swaps for the three months ended June 30, 2013 as compared to losses on these same interest rate swaps for the three months ended June 30, 2012; and the allocation of debt-related costs included in Corporate activities for the three months ended June 30, 2012, now allocated among our segments in 2013, in order to better align the capital structure of the corporation among the segments.

Results of Operations for Corporate activities for the Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012: Income from continuing operations for Corporate was $17.4 million for the six months ended June 30, 2013, compared to Loss from continuing operations of $9.8 million for the six months ended June 30, 2012. The variance from the prior year was primarily due to market interest rate changes creating unrealized, non-cash mark-to-market gains on certain interest rate swaps for the six months ended June 30, 2013 as compared to losses for these same interest rate swaps for the six months ended June 30, 2012; the allocation of debt-related costs included in Corporate activities for the six months ended June 30, 2012, now allocated among our segments in 2013, in order to better align the capital structure of the corporation among the segments; and costs originally allocated to our Energy Marketing segment, which could not be reclassified to discontinued operations in accordance with GAAP, and were included in Corporate activities for the six months ended June 30, 2012.

Discontinued Operations

Results of Operations for Discontinued Operations for the Three and Six Months Ended June 30, 2013, Compared to the Three and Six Months Ended June 30, 2012:

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. We recorded a Loss from discontinued operations, net of tax, for the three and six months ended June 30, 2012, of $1.2 million, including transaction related costs, net of tax of $0.3 million, and $6.6 million, including transaction related costs, net of tax of $2.5 million, respectively.

After the sale of Enserco and pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments, which we disputed. The buyer filed a petition in the Colorado District Court for the City and County of Denver, Colo., seeking an order compelling arbitration on all of the disputed claims. Following a hearing in July 2013, the court indicated it would enter an order remanding all but one of the disputed adjustment claims to arbitration. Upon entry of the final order, we will proceed as directed. The decision on this petition does not alter our evaluation of the merits of the adjustment claims.

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 Utilities Group and our Power Generation segment, and the payment of dividends to our shareholders. We could experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects, requirements imposed by state and federal agencies, and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow; however, the potential for unforeseen events affecting cash needs will continue to exist.

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

Cash Flow Activities

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

Cash provided by (used in):	2013	2012	Increase (Decrease)
Operating activities	$197,385	$176,699	$20,686
Investing activities	$(145,224)	$(36,699)	$(108,525)
Financing activities	$(36,990)	$(158,658)	$121,668

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

Operating Activities

Net cash provided by operating activities was $20.7 million higher for the six months ended June 30, 2013 than for the same period in 2012 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $26.2 million higher for the six months ended June 30, 2013 than for the same period in the prior year.
- Net inflows from operating assets and liabilities were $10.6 million for the six months ended June 30, 2013, a decrease of $15.8 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 during 2013.
- No cash contributions to the defined benefit pension plan were made in the six months ended June 30, 2013 compared to $25.0 million in the same period in the prior year.
- A $21.2 million decrease in net cash inflows from discontinued operations in 2013 compared to the same period in the prior year.

Investing Activities

Net cash used in investing activities was $145.2 million for the six months ended June 30, 2013, compared to net cash used in investing activities of $36.7 million for the same period in 2012 for a variance of $108.5 million. The variance was driven by:

- Cash proceeds of $108.8 million received from the 2012 sale of Enserco.
- Capital expenditures of approximately $62.2 million for the six months ended June 30, 2013 related to the construction of Cheyenne Prairie at our Electric Utilities segment offset by a decrease in capital spending at Oil and Gas.

Financing Activities

Net cash used in financing activities for the six months ended June 30, 2013 was $37.0 million, compared to net cash used in financing activities for the same period in 2012 of $158.7 million for a variance of $121.7 million.

- Proceeds from the sale of Enserco in 2012 were used to pay down short-term borrowings on the Revolving Credit Facility of approximately $110 million.
- Increased borrowings in 2013 to finance our construction of Cheyenne Prairie offset by decreased borrowings for capital expenditures in our Oil and Gas segment and the completion of Busch Ranch wind project in 2012.

Dividends

Dividends paid on our common stock totaled $33.8 million for the six months ended June 30, 2013, or $0.76 per share. On July 24, 2013, our board of directors declared a quarterly dividend of $0.38 per share payable Sept. 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 corporate Revolving Credit Facility that matures on Feb. 1, 2017, that has an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings are available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings under the Revolving Credit Facility are determined based upon the lowest credit ratings of S&P and Moody's that apply to our debt. Therefore, at our current credit rating the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 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 and was 0.25 percent based on our credit rating.

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

Credit Facility	Expiration	Current Capacity	Borrowings at June 30, 2013	Letters of Credit at June 30, 2013	Available Capacity at June 30, 2013
Revolving Credit Facility	Feb. 1, 2017	$500.0	$100.0	$43.2	$356.8

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain minimum net worth 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 June 30, 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.

Term Loans

On June 21, 2013, we entered into a new two-year $275 million term loan expiring on June 19, 2015. This new term loan replaced the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on Sept. 30, 2013, and $25 million in short-term borrowing under our Revolving Credit Facility. At June 30, 2013, the cost of borrowing under this new term loan was 1.375 percent based on LIBOR plus a margin of 1.125 percent.

Future Financing Plans

We are considering the following financing activities:

- Early refinancing of our $250 million, 9 percent senior unsecured bonds that mature in May 2014; and
- Long-term financing options for the 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 (Loss). For the three and six months ended June 30, 2013, respectively, we recorded $18.8 million and $26.2 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 $61.9 million at June 30, 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 5.5 years and 15.5 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 3.5 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 $19.3 million at June 30, 2013.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40 percent of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary’s liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders.
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 June 30, 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 June 30, 2013, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $187.4 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 $7.3 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 our credit ratings, management believes that we will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. Credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings and outlook of BHC at June 30, 2013:

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

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* On July 24, 2013, S&P upgraded our credit rating to BBB with a Stable outlook.
** On May 10, 2013, Fitch upgraded our credit rating to BBB from BBB-.

The following table represents the credit ratings of Black Hills Power's Senior Secured Debt at June 30, 2013:

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

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* On July 24, 2013, S&P upgraded the BHP credit rating to A- with a Stable outlook.

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Capital Requirements

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

	Expenditures for the Six Months Ended June 30, 2013	Total 2013 Planned Expenditures	Total 2014 Planned Expenditures	Total 2015 Planned Expenditures
Utilities:				
Electric Utilities	$98,226	$284,200	$230,500	$127,600
Gas Utilities	22,992	59,800	58,000	43,000
Non-regulated Energy:				
Power Generation	3,443	5,900	4,800	2,400
Coal Mining	2,784	7,100	6,000	5,100
Oil and Gas	21,380	98,300	84,300	109,100
Corporate	7,866	12,700	6,500	5,700
	$156,691	$468,000	$390,100	$292,900

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

Contractual Obligations

Except as noted below, there have been no significant changes in the contractual obligations from those previously disclosed in Note 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:

- Cheyenne Light renewed and received FERC approval for an agreement with Basin Electric whereby Cheyenne Light will receive 40 megawatts of capacity and energy from Basin Electric through Sept. 30, 2014.
- Cheyenne Light renewed and received FERC approval for an agreement with Basin Electric whereby Cheyenne Light will provide 40 megawatts of capacity and energy to Basin Electric through Sept. 30, 2014.

Construction Commitments

Construction of Cheyenne Prairie, a 132 megawatt natural gas-fired electric generating facility jointly owned 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 June 30, 2013, contracts for equipment purchases and for construction were 62 percent and 22 percent committed, respectively.

Purchase and Sale Agreement

Black Hills Wyoming entered into an agreement to sell its 40 megawatt CTII natural gas-fired generating unit to the City of Gillette, Wyo. for approximately $22 million, subject to closing adjustments. The sale is expected to close in August 2014 upon the expiration of an existing power sales agreement under which Black Hills Wyoming sells the output of the CTII to Cheyenne Light.

Sale of Enserco Energy Inc.

After the sale of Enserco, our Energy Marketing segment, on Feb. 29, 2012 and pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments, which we disputed. The buyer filed a petition in the Colorado District Court for the City and County of Denver, Colo., seeking an order compelling arbitration on all of the disputed claims. Following a hearing in July 2013, the court indicated it would enter an order remanding all but one of the disputed adjustment claims to arbitration. Upon entry of the final order, we will proceed as directed. The decision on this petition does not alter our evaluation of the merits of the adjustment claims.

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 completed in 2012. The guarantee expired March 29, 2013, upon fulfillment of all contractual obligations.

We had a guarantee of $7.5 million to Cross Timbers Energy Services for the performance and payment obligation of Black Hills Utility Holdings for natural gas supply purchases which expired on June 30, 2013 and was converted to a letter of credit for $5 million as a replacement to this guarantee.

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 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

FORWARD-LOOKING INFORMATION

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

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 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:

	June 30, 2013	Dec. 31, 2012	June 30, 2012
Net derivative (liabilities) assets	$(7,203)	$(8,533)	$(12,453)
Cash collateral offset in Derivatives	7,203	8,576	15,925
Cash Collateral included in Other current assets	2,938	4,354	—
Net receivable (liability) position	$2,938	$4,397	$3,472

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 June 30, 2013 were as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2013					
Swaps - MMBtu	—	—	1,246,000	1,154,000	2,400,000
Weighted Average Price per MMBtu	$—	$—	$3.33	$3.50	$3.41
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	720,000	862,500	500,000	225,000	2,307,500
Weighted Average Price per MMBtu	$4.28	$3.99	$4.08	$4.33	$4.13

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2013					
Swaps - Bbls	—	—	15,000	15,000	30,000
Weighted Average Price per Bbl	$—	$—	$110.20	$101.75	$105.98
Puts - Bbls	—	—	39,000	36,000	75,000
Weighted Average Price per Bbl	$—	$—	$79.81	$80.63	$80.20
Calls - Bbls	—	—	39,000	36,000	75,000
Weighted Average Price per Bbl	$—	$—	$97.08	$97.25	$97.16
2014					
Swaps - Bbls	51,000	60,000	57,000	57,000	225,000
Weighted Average Price per Bbl	$94.50	$90.65	$90.55	$90.66	$91.50
2015					
Swaps - Bbls	55,500	30,000	30,000	—	115,500
Weighted Average Price per Bbl	$89.98	$87.53	$87.53	$—	$88.71

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 10 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:

	June 30, 2013		Dec. 31, 2012		June 30, 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	3.50	0.50	4.00	1.00	4.50	1.50
Derivative liabilities, current	$6,965	$ 61,899	$7,039	$ 88,148	$6,766	$ 78,001
Derivative liabilities, non-current	$12,384	$ —	$16,941	$ —	$18,976	$ 15,336
Pre-tax accumulated other comprehensive income (loss)	$(19,349)	$ —	$(23,980)	$ —	$(25,742)	$ —
Pre-tax gain (loss)	$—	$ 26,249	$—	$ 1,882	$—	$ (3,507)
Cash collateral receivable (payable) included in derivatives	$—	$ 5,960	$—	$ 5,960	$—	$ 6,160

* 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 5.5 years and de-designated swaps totaling $150.0 million terminate in 15.5 years.

Based on June 30, 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 June 30, 2013. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended June 30, 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 13 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 13 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 2012 Annual Report on Form 10-K.

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
April 1, 2013 - April 30, 2013	—	$—	—	—
May 1, 2013 - May 31, 2013	868	$49.36	—	—
June 1, 2013 - June 30, 2013	—	$—	—	—
Total	868	$49.36	—	—

(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 Number	Description
Exhibit 4.3*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant’s Form 10-K for 2000).
Exhibit 10 *	Credit Agreement dated June 21, 2013 among Black Hills Corporation, as Borrower, JPMorgan Chase Bank, N. A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to Registrant’s Form 8-K filed on June 24, 2013).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

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

SIGNATURES

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

BLACK HILLS CORPORATION

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

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

Dated: August 6, 2013

INDEX TO 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).
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