BLACK HILLS CORP /SD/
Form 10-Q
August 07, 2012

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, 2012

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, 2012
Common stock, $1.00 par value	44,188,286 shares

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS
AND ACCOUNTING STANDARDS

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)
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation
BHEP	Black Hills Exploration and Production, Inc., representing our Oil and Gas segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Electric Generation	Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Service Company	Black Hills Service Company, a direct wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
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, a direct wholly-owned subsidiary of Black Hills Electric Generation
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine
CVA	Credit Valuation Adjustment
CWIP	Construction Work-In-Progress
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated.
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DRIP	Dividend Reinvestment and Stock Purchase Plan

Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
ECA	Energy Cost Adjustment
Enserco	Enserco Energy Inc., representing our Energy Marketing segment, sold February 29, 2012
Equity Forward Instrument	Equity Forward Agreement with J.P. Morgan connected to a public offering of 4,413,519 shares of Black Hills Corporation common stock

3

FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles of the United States
Global Settlement	Settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
IFRS	International Financial Reporting Standards
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent Power Producer
IRS	Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand standard cubic feet
Mcfe	One thousand standard cubic feet equivalent. Natural gas liquid is converted by dividing gallons by 7. Crude oil is converted by multiplying barrels by 6.
MMBtu	One million British thermal units
MSHA	Mine Safety and Health Administration
MW	Megawatt
MWh	Megawatt-hour
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NGL	Natural Gas Liquids
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OTC	Over-the-counter
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $500 million five-year revolving credit facility which commenced on February 1, 2012 and expires on February 1, 2017
S&P	Standard and Poor's
SEC	United States Securities and Exchange Commission
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands, except per share amounts)			
Revenue:				
Utilities	$214,946	$236,053	$551,601	$610,749
Non-regulated energy	27,417	24,596	56,613	50,735
Total revenue	242,363	260,649	608,214	661,484
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of gas sold	63,452	103,827	220,635	314,338
Operations and maintenance	59,563	58,689	124,323	126,098
Non-regulated energy operations and maintenance	20,713	22,436	43,308	46,626
Depreciation, depletion and amortization	41,431	32,246	79,990	64,156
Taxes - property, production and severance	9,478	7,239	20,988	15,436
Impairment of long-lived assets	26,868	—	26,868	—
Other operating expenses	267	52	1,463	303
Total operating expenses	221,772	224,489	517,575	566,957
Operating income	20,591	36,160	90,639	94,527
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums, discounts and realized settlements on interest rate swaps)	(27,762)	(28,593)	(57,676)	(57,796)
Allowance for funds used during construction - borrowed	963	2,991	1,481	6,354
Capitalized interest	131	2,783	292	5,217
Unrealized gain (loss) on interest rate swaps, net	(15,552)	(7,827)	(3,507)	(2,362)
Interest income	627	463	1,064	1,011
Allowance for funds used during construction - equity	195	192	472	487
Other income, net	888	504	2,360	1,235
Total other income (expense)	(40,510)	(29,487)	(55,514)	(45,854)
Income (loss) before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	(19,919)	6,673	35,125	48,673
Equity in earnings (loss) of unconsolidated subsidiaries	22	40	(34)	1,033
Income tax benefit (expense)	7,574	(3,007)	(12,143)	(16,932)
Income (loss) from continuing operations	(12,323)	3,706	22,948	32,774
Income (loss) from discontinued operations, net of tax	(1,160)	4,046	(6,644)	1,888
Net income (loss) available for common stock	(13,483)	7,752	16,304	34,662
Other comprehensive income (loss), net of tax	(608)	288	(774)	(1,290)

Comprehensive income (loss)	$(14,091)	$8,040	$15,530	$33,372
Income (loss) per share, Basic -				
Income (loss) from continuing operations, per share	$(0.28)	$0.09	$0.52	$0.84
Income (loss) from discontinued operations, per share	(0.03)	0.11	(0.15)	0.05
Total income (loss) per share, Basic	$(0.31)	$0.20	$0.37	$0.89
Income (loss) per share, Diluted -				
Income (loss) from continuing operations, per share	$(0.28)	$0.09	$0.52	$0.82
Income (loss) from discontinued operations, per share	(0.03)	0.10	(0.15)	0.05
Total income (loss) per share, Diluted	$(0.31)	$0.19	$0.37	$0.87
Weighted average common shares outstanding:				
Basic	43,799	39,109	43,765	39,084
Diluted	43,799	39,823	43,984	39,793
Dividends paid per share of common stock	$0.370	$0.365	$0.740	$0.730

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

5

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	June 30, 2012	December 31, 2011	June 30, 2011
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$40,110	$21,628	$21,971
Restricted cash and equivalents	4,772	9,254	3,710
Accounts receivable, net	109,157	156,774	108,203
Materials, supplies and fuel	61,455	84,064	61,104
Derivative assets, current	16,595	18,583	9,544
Income tax receivable, net	12,141	9,344	6,661
Deferred income tax assets, net, current	30,401	37,202	20,924
Regulatory assets, current	34,781	59,955	37,584
Other current assets	26,591	21,266	17,499
Assets of discontinued operations	—	340,851	358,669
Total current assets	336,003	758,921	645,869
Investments	16,208	17,261	17,302
Property, plant and equipment	3,863,380	3,724,016	3,550,783
Less accumulated depreciation and depletion	(1,006,827)	(934,441)	(913,503)
Total property, plant and equipment, net	2,856,553	2,789,575	2,637,280
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,731	3,843	3,955
Derivative assets, non-current	1,770	1,971	724
Regulatory assets, non-current	186,886	182,175	139,309
Other assets, non-current	19,733	19,941	19,325
Total other assets	565,516	561,326	516,709
TOTAL ASSETS	$3,774,280	$4,127,083	$3,817,160

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)

	June 30, 2012	December 31, 2011	June 30, 2011
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$59,739	$104,748	$84,195
Accrued liabilities	158,240	151,319	131,175
Derivative liabilities, current	85,675	84,367	65,627
Regulatory liabilities, current	16,785	16,231	17,220
Notes payable	225,000	345,000	380,000
Current maturities of long-term debt	227,590	2,473	3,613
Liabilities of discontinued operations	—	173,929	182,723
Total current liabilities	773,029	878,067	864,553
Long-term debt, net of current maturities	1,044,891	1,280,409	1,183,583
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	316,393	300,988	304,860
Derivative liabilities, non-current	42,077	49,033	17,281
Regulatory liabilities, non-current	114,593	108,217	83,643
Benefit plan liabilities	162,530	177,480	131,169
Other deferred credits and other liabilities	124,482	123,553	124,002
Total deferred credits and other liabilities	760,075	759,271	660,955
Commitments and contingencies (See Notes 6, 7, 10, 11, 13 and 16)			
Stockholders' equity:			
Common stockholders' —			
Common stock $1 par value: 100,000,000 shares authorized: issued 44,176,520; 43,957,502 and 39,462,001 shares, respectively	44,177	43,958	39,462
Additional paid-in capital	727,613	722,623	602,961
Retained earnings	460,324	476,603	491,208
Treasury stock at cost – 69,657; 32,766 and 23,637 shares, respectively	(2,177)	(970)	(691)
Accumulated other comprehensive income (loss)	(33,652)	(32,878)	(24,871)
Total stockholders' equity	1,196,285	1,209,336	1,108,069
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,774,280	$4,127,083	$3,817,160

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,	
	2012	2011
Operating activities:	(in thousands)	
Net income (loss) available to common stock	$16,304	$34,662
(Income) loss from discontinued operations, net of tax	6,644	(1,888)
Income (loss) from continuing operations	22,948	32,774
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	79,990	64,156
Deferred financing cost amortization	4,050	3,199
Impairment of long-lived assets	26,868	—
Derivative fair value adjustments	(4,895)	(3,235)
Stock compensation	3,269	3,185
Unrealized mark-to-market (gain) loss on interest rate swaps	3,507	2,362
Deferred income taxes	11,200	29,836
Equity in (earnings) loss of unconsolidated subsidiaries	34	(1,033)
Allowance for funds used during construction - equity	(472)	(487)
Employee benefit plans	10,492	7,287
Other adjustments, net	4,258	(160)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	22,609	1,811
Accounts receivable, unbilled revenues and other current assets	42,262	51,615
Accounts payable and other current liabilities	(55,015)	(65,673)
Regulatory assets	14,533	32,029
Regulatory liabilities	(385)	11,573
Contributions to defined benefit pension plans	(25,000)	(550)
Other operating activities, net	(4,738)	(6,190)
Net cash provided by operating activities of continuing operations	155,515	162,499
Net cash provided by (used in) operating activities of discontinued operations	21,184	19,518
Net cash provided by operating activities	176,699	182,017
Investing activities:		
Property, plant and equipment additions	(148,807)	(223,456)
Other investing activities	4,095	799
Net cash provided by (used in) investing activities of continuing operations	(144,712)	(222,657)
Proceeds from sale of business operations	108,837	—
Net cash provided by (used in) investing activities of discontinued operations	(824)	(2,407)
Net cash provided by (used in) investing activities	(36,699)	(225,064)
Financing activities:		
Dividends paid on common stock	(32,583)	(29,530)
Common stock issued	1,510	1,437
Short-term borrowings - issuances	56,453	564,000
Short-term borrowings - repayments	(176,453)	(433,000)
Long-term debt - repayments	(10,418)	(4,052)

Other financing activities	2,833	(16)
Net cash provided by (used in) financing activities of continuing operations	(158,658)	98,839
Net cash provided by (used in) financing activities of discontinued operations	—	(157)
Net cash provided by (used in) financing activities	(158,658)	98,682
Net change in cash and cash equivalents	(18,658)	55,635
Cash and cash equivalents, beginning of period*	58,768	32,438
Cash and cash equivalents, end of period*	$40,110	$88,073

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* Cash and cash equivalents include cash of discontinued operations of $37.1 million, $66.1 million and $16.0 million at December 31, 2011, June 30, 2011 and December 31, 2010, respectively.

See Note 3 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2011 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 2011 Annual Report on Form 10-K filed with the SEC.

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, 2012, December 31, 2011 and June 30, 2011 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 gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2012 and June 30, 2011, and our financial condition as of June 30, 2012, December 31, 2011, and June 30, 2011 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 February 29, 2012, we sold our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations. For further information see Note 18.

Certain prior year data presented in the financial statements has been reclassified to conform to the current year presentation. Specifically, the Company has reclassified deferred financing cost amortization into a separate line on the Condensed Consolidated Statements of Cash Flows. This reclassification had no effect on total assets, net income, cash flows or earnings per share.

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

Recently Adopted Accounting Standards and Legislation

Other Comprehensive Income: Presentation of Comprehensive Income, ASU 2011-05 and ASU 2011-12

FASB issued an accounting standards update amending ASC 220, Comprehensive Income, to improve the comparability, consistency and transparency of reporting of comprehensive income. It amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU 2011-05 requires retrospective application, and it is effective for the fiscal years, and interim periods within those years beginning after December 15, 2011. In December 2011, FASB issued ASU 2011-12, which indefinitely deferred the provisions of ASU 2011-05 requiring the presentation of reclassification adjustments on the face of the financial statements for items reclassified from other comprehensive income to net income.

At December 31, 2011, we elected to early adopt the provisions of ASU 2011-05 as amended by ASU 2011-12. The adoption changed our presentation of certain financial statements and provided additional details in the notes to the financial statements, but did not have any other impact on our financial statements.

Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements, ASU 2011-04

In May 2011, FASB issued an accounting standards update amending ASC 820, Fair Value Measurements and Disclosures, to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements - quantitative information about unobservable inputs used, a description of the valuation processes used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a non-financial asset that is different from the asset's highest and best use - the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required - the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosure of all transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-04 is effective for fiscal years, and interim periods within those years, beginning after December 31, 2011. The amendment required additional details in notes to financial statements, but did not have any other impact on our financial statements. Additional disclosures are included in Notes 14 and 15.

Intangibles - Goodwill and Other: Testing Goodwill for Impairment, ASU 2011-08

In September 2011, the FASB issued an amendment to ASC 350, Intangibles - Goodwill and Other, to provide an option to perform a qualitative assessment to determine whether further impairment testing of goodwill is necessary. Specifically, an entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. This standard is effective for annual and interim goodwill impairment testing performed for fiscal years beginning after December 15, 2011. We perform our annual impairment testing in November of each year. The adoption of this standard will not have an impact on our financial statements.

Recently Issued Accounting Standards and Legislation

Balance Sheet: Disclosure about Offsetting Assets and Liabilities, ASU 2011-11
In December 2011, the FASB issued revised accounting guidance to amend ASC 210, Balance Sheet, related to the existing disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve comparability of balance sheets prepared under GAAP and IFRS. The revised disclosure guidance affects all companies that have financial instruments and derivative instruments that are either offset in the balance sheet (i.e., presented on a net basis) or subject to an enforceable master netting and/or similar arrangement. In addition, the revised guidance requires that certain enhanced quantitative and qualitative disclosures are made with respect to a company's netting arrangements and/or rights of offset associated with its financial instruments and/or derivative instruments. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning January 1, 2013. The adoption of this standard will not have an impact on our financial position, results of operations or cash flows.

Intangible - Goodwill and Other: Testing Indefinite Lived Intangible Assets for Impairment, ASU 2012-02

In July 2012, the FASB issued an amendment to ASC 350, Intangibles - Goodwill and Other, to provide an option to perform a qualitative assessment to determine whether further impairment testing of indefinite lived intangible assets is necessary. This ASU aligns the impairment testing for intangible assets with that of goodwill as amended by ASU 2011-11. This guidance is effective for interim and annual periods beginning after September 15, 2012, with early adoption permitted. The adoption of this standard will not have an impact on our financial statements, results of operations or cash flows.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Six Months Ended June 30, 2012	June 30, 2011
	(in thousands)	
Non-cash investing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$52,204	$34,171
Capitalized assets associated with retirement obligations	$3,406	$—
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(55,364)	$(49,425)
Income taxes, net	$(383)	$(10,726)

(4) MATERIALS, SUPPLIES AND FUEL

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

	June 30, 2012	December 31, 2011	June 30, 2011
Materials and supplies	$41,963	$40,838	$36,382
Fuel - Electric Utilities	8,089	8,201	8,808
Natural gas in storage held for distribution	11,403	35,025	15,914
Total materials, supplies and fuel	$61,455	$84,064	$61,104

(5) ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Accounts receivable consists primarily of customer trade accounts. The Gas Utilities' accounts receivable balance fluctuates primarily due to seasonality. We maintain an allowance for doubtful accounts that reflects our best estimate of probable uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect our ability to collect.

Following is a summary of receivables (in thousands) as of:

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
Oil and Gas	13,749	—	(105)	13,644
Coal Mining	1,982	—	—	1,982
Power Generation	197	—	—	197
Corporate	1,130	—	—	1,130
Total	$74,021	$36,811	$(1,675)	$109,157

December 31, 2011	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$42,773	$21,151	$(545)	$63,379
Gas Utilities	39,353	38,992	(1,011)	77,334
Oil and Gas	11,282	—	(105)	11,177
Coal Mining	4,056	—	—	4,056
Power Generation	282	—	—	282
Corporate	546	—	—	546
Total	$98,292	$60,143	$(1,661)	$156,774

June 30, 2011	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$38,067	$16,535	$(685)	$53,917
Gas Utilities	33,572	11,891	(1,420)	44,043
Oil and Gas	7,803	—	(161)	7,642
Coal Mining	1,652	—	—	1,652
Power Generation	106	—	—	106
Corporate	843	—	—	843
Total	$82,043	$28,426	$(2,266)	$108,203

(6) NOTES PAYABLE

Our credit facility and debt securities contain certain restrictive financial covenants. As of June 30, 2012, we were in compliance with all of these covenants.

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

	June 30, 2012		December 31, 2011		June 30, 2011	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$75,000	$36,256	$195,000	$43,700	$130,000	$43,000
Term Loan due 2011[(a)]	—	—	—	—	100,000	—
Term Loan due 2013 [(b)]	150,000	—	150,000	—	150,000	—
Total	$225,000	$36,256	$345,000	$43,700	$380,000	$43,000

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(a) The short-term loan was renegotiated to a longer term note, maturing on September 30, 2013.
(b) In June 2012, this short-term loan was extended for one year. See discussion below.

Revolving Credit Facility

On February 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring February 1, 2017. The facility contains an accordion feature allowing us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million. The Revolving Credit Facility can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50%, 1.50% and 1.50%, respectively, at June 30, 2012. The facility contains a commitment fee that is charged on the unused amount of the Revolving Credit Facility. Based upon current credit ratings, the fee is 0.25%.

Deferred financing costs on the new facility of $2.8 million are being amortized over the estimated useful life of the Revolving Credit Facility and are included in Interest expense on the accompanying Condensed Consolidated Statements of Income and Comprehensive Income. Upon entering into the new facility, $1.5 million of deferred financing costs relating to the previous credit facility were written off through Interest expense.

Term Loan due 2013

On June 24, 2012, we extended the term of the $150 million term loan to June 24, 2013. The cost of borrowing is based on 1.10% over LIBOR.

Debt Covenants

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

	As of June 30, 2012	Covenant Requirement	
Consolidated Net Worth	$1,196,285	Greater than	$892,283
Recourse Leverage Ratio	56.8 %	Less than	65.0 %

(7) LONG TERM DEBT

On May 15, 2012, Black Hills Power repaid its 4.8% Pollution Control Refund Revenue Bonds in full for $6.5 million principal and interest. These bonds were originally due to mature on October 1, 2014.

(8) EARNINGS PER SHARE

Basic income (loss) per share from continuing operations is computed by dividing Income (loss) from continuing operations by the weighted-average number of common shares outstanding during the period. Diluted income (loss) per share is computed by including all dilutive common shares potentially outstanding during a period.

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,	
	2012	2011	2012	2011
Income (loss) from continuing operations	$(12,323)	$3,706	$22,948	$32,774
Weighted average shares - basic	43,799	39,109	43,765	39,084
Dilutive effect of:				
Restricted stock	—	148	150	140
Stock options	—	20	15	20
Equity forward instruments	—	533	—	496
Other dilutive effects	—	13	54	53
Weighted average shares - diluted	43,799	39,823	43,984	39,793

13

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 potentially dilutive shares excluded due to our net loss for second quarter of 2012, the following outstanding securities were also excluded in the computation of diluted income (loss) per share from continuing operations as their inclusion would have been anti-dilutive (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Stock options	99	102	113	81
Restricted stock	66	24	48	16
Other stock	42	31	29	15
Anti-dilutive shares	207	157	190	112

(9) COMPREHENSIVE INCOME (LOSS)

The following table presents the components of our comprehensive income (loss) (in thousands):

Three Months Ended June 30, 2012	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Fair value adjustment of derivatives designated as cash flow hedges	$178	$(167)	$11
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	(1,051)	432	(619)
Other comprehensive income (loss)	$(873)	$265	$(608)

Three Months Ended June 30, 2011	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Fair value adjustment of derivatives designated as cash flow hedges	$(996)	$231	$(765)
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	1,617	(564)	1,053
Other comprehensive income (loss)	$621	$(333)	$288

Six Months Ended June 30, 2012	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Fair value adjustment of derivatives designated as cash flow hedges	$699	$(112)	$587
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	(2,238)	877	(1,361)
Other comprehensive income (loss)	$(1,539)	$765	$(774)

Six Months Ended June 30, 2011	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Fair value adjustment of derivatives designated as cash flow hedges	$(4,781)	$1,868	$(2,913)
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	2,478	(855)	1,623
Other comprehensive income (loss)	$(2,303)	$1,013	$(1,290)

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets are as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2011	$(13,802)	$(19,076)	$(32,878)
Other comprehensive income (loss)	(774)	—	(774)
Ending Balance June 30, 2012	$(14,576)	$(19,076)	$(33,652)

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2010	$(12,439)	$(11,142)	$(23,581)
Other comprehensive income (loss)	(1,290)	—	(1,290)
Ending Balance June 30, 2011	$(13,729)	$(11,142)	$(24,871)

(10) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the six months ended June 30, 2012 from the amount reported in Note 11 of the Notes to Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Equity Compensation Plans

- We granted 66,690 target performance shares to certain officers and business unit leaders for the January 1, 2012 through December 31, 2014 performance period during the six months ended June 30, 2012. Actual shares are issued after the end of the performance period. Performance shares are awarded based on our total stockholder return over the designated performance period as measured against a selected peer group and can range from 0% to 200% of target. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria. The performance awards are paid 50% in cash and 50% in shares of common stock. The grant date fair value was $32.26 per share.

- We granted 145,787 shares of restricted common stock and restricted stock units during the six months ended June 30, 2012. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $5.1 million will be recognized over the vesting period.

- Stock options totaling 41,206 shares of common stock were exercised during the six months ended June 30, 2012 at a weighted-average exercise price of $28.28 per share, providing $1.2 million of proceeds.

- We issued 3,690 shares of common stock under our short-term incentive compensation plan during the six months ended June 30, 2012. Pre-tax compensation cost related to the awards was approximately $0.1 million, which was expensed in 2011.

Stock-based compensation expense for the three months ended June 30, 2012 and 2011 was $1.5 million and $0.9 million, respectively, and for the six months ended June 30, 2012 and 2011 was $3.3 million and $3.1 million, respectively.

As of June 30, 2012, total unrecognized compensation expense related to non-vested stock awards was $10.3 million and is expected to be recognized over a weighted-average period of 2.2 years.

Dividend Reinvestment and Stock Purchase Plan

We have a DRIP under which stockholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We are currently issuing new shares. We issued 52,247 new shares at a weighted-average price of $32.70 during the six months ended June 30, 2012. Unissued common stock totaling 401,017 shares was available for future offering under the DRIP at June 30, 2012.

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, 2012, 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, 2012:

- 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, 2012, the restricted net assets at our Utilities Group were approximately $215.1 million.

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

(11) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Pension Plans"). One covers certain eligible employees of Black Hills Service Company, Black Hills Power, WRDC and BHEP, one covers certain eligible employees of Cheyenne Light, and one covers certain eligible employees of Black Hills Energy. The Pension Plan benefits are based on years of service and compensation levels.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Service cost	$1,430	$1,356	$2,860	$2,711
Interest cost	3,687	3,732	7,374	7,464
Expected return on plan assets	(4,084)	(4,239)	(8,168)	(8,478)
Prior service cost	22	25	44	50
Net loss (gain)	2,408	1,135	4,816	2,270
Net periodic benefit cost	$3,463	$2,009	$6,926	$4,017

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor the following retiree healthcare plans (the "Healthcare Plans"): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Healthcare Plans and who retire on or after meeting certain eligibility requirements are entitled to postretirement healthcare benefits.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Service cost	$402	$375	$804	$750
Interest cost	523	542	1,046	1,084
Expected return on plan assets	(19)	(41)	(38)	(82)
Prior service cost (benefit)	(125)	(120)	(250)	(240)
Net loss (gain)	222	169	444	338
Net periodic benefit cost	$1,003	$925	$2,006	$1,850

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives (the "Supplemental Plans"). The Supplemental Plans are non-qualified defined benefit plans.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Service cost	$246	$257	$492	$514
Interest cost	331	325	662	649
Prior service cost	1	1	2	2
Net loss (gain)	202	128	404	255
Net periodic benefit cost	$780	$711	$1,560	$1,420

Contributions

We anticipate that we will make contributions to the benefit plans during 2012 and 2013. Contributions to the Pension Plans will be made in cash, and contributions to the Healthcare Plans and the Supplemental Plans are expected to be made in the form of benefit payments. Contributions are as follows (in thousands):

	Contributions Made Three Months Ended June 30, 2012	Contributions Made Six Months Ended June 30, 2012	Additional Contributions Anticipated for 2012	Contributions Anticipated for 2013
Defined Benefit Pension Plans	$—	$25,000	$—	$4,500
Non-pension Defined Benefit Postretirement Healthcare Plans	$1,063	$2,126	$2,125	$4,380
Supplemental Non-qualified Defined Benefit Plans	$278	$556	$555	$1,090

(12) BUSINESS SEGMENTS INFORMATION

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.

On February 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been classified as discontinued operations have been reclassified to our Corporate segment. For further information see Note 18.

We conduct our operations through the following five reportable segments:

Utilities Group —

- Electric Utilities, which supplies electric utility service to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility service to Cheyenne, Wyoming and vicinity; and
- Gas Utilities, which supplies natural gas utility service to areas in Colorado, Iowa, Kansas and Nebraska.

Non-regulated Energy Group —

- Oil and Gas, which acquires, explores for, develops and produces crude oil and natural gas interests located in the Rocky Mountain region and other states;
- Power Generation, which produces and sells power and capacity to wholesale customers from power plants located in Wyoming and Colorado; and
- Coal Mining, which engages in the mining and sale of coal from our mine near Gillette, Wyoming.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Segment information included in the accompanying Condensed Consolidated Statements of Income and Comprehensive Income and Condensed Consolidated Balance Sheets was as follows (in thousands):

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

Three Months Ended June 30, 2011	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$136,131	$3,410	$8,614
Gas	99,922	—	4,440
Non-regulated Energy:			
Oil and Gas	18,838	—	(79)
Power Generation	891	6,889	548
Coal Mining	6,266	9,274	(381)
Corporate [(b)(c)]	—	—	(9,443)

Intercompany eliminations	—	(20,972)	7
Total	$262,048	$(1,399)	$3,706

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:			
Oil and Gas [(a)]	42,266	—	(19,608)
Power Generation	1,937	36,424	10,840
Coal Mining	12,410	15,706	2,234
Corporate [(b)(c)]	—	—	(9,789)
Intercompany eliminations	—	(60,340)	—
Total	$608,214	$—	$22,948

Six Months Ended June 30, 2011	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$280,561	$7,249	$18,863
Gas	330,188	—	23,703
Non-regulated Energy:			
Oil and Gas	36,744	—	(794)
Power Generation	1,578	13,822	1,734
Coal Mining	13,880	17,155	(1,679)
Corporate [(b)(c)]	—	—	(8,992)
Intercompany eliminations	—	(39,693)	(61)
Total	$662,951	$(1,467)	$32,774

(a) Income (loss) from continuing operations includes a $17.3 million non-cash after-tax ceiling test impairment charge. See Note 17 for further information.

(b) Income (loss) from continuing operations includes $10.1 million and $2.3 million net after-tax mark-to-market loss on interest rate swaps for the three and six months ended June 30, 2012, respectively, and a $5.1 million and $1.5 million net after-tax mark-to-market loss on interest rate swaps for the three and six months ended June 30, 2011, respectively.

(c) Certain direct corporate costs and inter-segment interest expense previously allocated to our Energy Marketing segment were not classified as discontinued operations but were included in the Corporate segment. See Note 18 for further information.

19

Total Assets (net of inter-company eliminations)	June 30, 2012	December 31, 2011		June 30, 2011	
Utilities:					
Electric [a]	$2,300,948	$2,254,914		$1,900,806	
Gas	684,545	746,444		659,349	
Non-regulated Energy:					
Oil and Gas	416,617	425,970		366,270	
Power Generation [a]	122,856	129,121		353,794	
Coal Mining	90,021	88,704		89,627	
Corporate	159,293	141,079	(b)	88,645	(b)
Discontinued operations	—	340,851	(c)	358,669	(c)
Total assets	$3,774,280	$4,127,083		$3,817,160	

(a) The PPA under which the new generating facility was constructed at our Pueblo Airport Generation site by Colorado IPP to support Colorado Electric customers is accounted for as a capital lease. Therefore, commencing December 31, 2011, assets previously recorded at Power Generation are now accounted for at Colorado Electric as a capital lease.
(b) Assets of the Corporate segment were restated due to deferred taxes that were not classified as discontinued operations.
(c) See Note 18 for further information relating to discontinued operations.

(13) 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 2011 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:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated segment; and

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

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

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 investment grade companies and credit quality municipalities and electric cooperatives, 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, 2012, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies, municipal cooperatives and federal agencies. Credit exposure with non-investment grade or non-rated counterparties, was supported partially through letters of credit, prepayments or parental guarantees.

We actively manage our exposure to certain market and credit risks as described in Note 3 of the Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K. Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income and Comprehensive Income are detailed below and within Note 14.

Oil and Gas Exploration and Production

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.

We hold a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on those OTC swaps and options. These transactions were designated at inception as cash flow hedges, documented under accounting for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives are marked to fair value and are 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 Accumulated other comprehensive income (loss) and the ineffective portion, if any, is reported in Revenue.

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

	June 30, 2012		December 31, 2011		June 30, 2011	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional [(a)]	672,000	9,020,500	528,000	5,406,250	463,500	5,969,250
Maximum terms in years [(b)]	1.50	1.25	1.25	1.75	1.00	0.25
Derivative assets, current	$2,483	$4,386	$729	$8,010	$449	$6,160
Derivative assets, non-current	$1,316	$255	$771	$1,148	$214	$456
Derivative liabilities, current	$456	$452	$2,559	$—	$2,385	$—
Derivative liabilities, non-current	$981	$331	$811	$7	$1,201	$117
Pre-tax accumulated other comprehensive income (loss)	$1,727	$3,305	$(1,928)	$9,152	$3,173	$6,499
Cash collateral included in Derivative liabilities	$613	$553	$—	$—	$—	$—
Cash collateral included in Other current assets	$267	$51	$—	$—	$—	$—
Expense included in Revenue [(c)]	$245	$51	$58	$—	$250	$—

(a) Crude oil in Bbls, gas in MMBtus

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

(c) Represents the amortization of put premiums.

Based on June 30, 2012 market prices, a $4.5 million gain would be reclassified from AOCI during the next 12 months. Estimated and actual realized gains will change during future periods as market prices fluctuate.

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 certain 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. Gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated utility operations. Accordingly, the hedging activity is recognized in the Condensed Consolidated Statements of Income and Comprehensive Income 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, 2012		December 31, 2011		June 30, 2011	
	Notional (MMBtus)	Latest Expiration (months)	Notional (MMBtus)	Latest Expiration (months)	Notional (MMBtus)	Latest Expiration (months)
Natural gas futures purchased	12,440,000	78	14,310,000	84	7,820,000	21
Natural gas options purchased	2,840,000	9	1,720,000	3	1,560,000	9
Natural gas basis swaps purchased	7,270,000	78	7,160,000	60	—	—

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

	June 30, 2012	December 31, 2011	June 30, 2011
Derivative assets, current	$9,726	$ 9,844	$2,935
Derivative assets, non-current	$199	$ 52	$53
Derivative liabilities, non-current	$6,453	$ 7,156	$175
Net unrealized (gain) loss included in Regulatory assets or liabilities	$13,691	$ 17,556	$4,229
Included in Derivatives:			
Cash collateral receivable (payable)	$15,925	$ 19,416	$6,254
Option premiums and commissions	$1,238	$ 880	$760

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, 2012		December 31, 2011		June 30, 2011	
	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	4.50	1.50	5.00	2.00	5.50	0.50
Derivative liabilities, current	$6,766	$ 78,001	$6,513	$ 75,295	$6,900	$ 56,342
Derivative liabilities, non-current	$18,976	$ 15,336	$20,363	$ 20,696	$15,788	$ —
Pre-tax accumulated other comprehensive income (loss)	$(25,742)	$ —	$(26,876)	$ —	$(22,688)	$ —
Pre-tax gain (loss)	$—	$ (3,507)	$—	$ (42,010)	$—	$ (2,362)
Cash collateral receivable (payable) included in derivative	$—	$ 6,160	$—	$ —	$—	$ —

* 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 million notional terminate in 6.5 years and de-designated swaps totaling $150 million notional terminate in 16.5 years.

Collateral requirements based on our corporate credit rating apply to $50 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 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.

Based on June 30, 2012 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $6.8 million would be reclassified from AOCI during the next 12 months. Estimated and realized losses will change during future periods as market interest rates change.

(14) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

Assets and liabilities carried at fair value are classified and disclosed in one of the following categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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.

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

Oil and Gas Segment:

- The commodity option contracts for the Oil and Gas segment are valued under the market approach and include calls and puts. Fair value was derived using quoted prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through multiple sources and therefore support Level 2 disclosure.

- The commodity basis swaps for the Oil and Gas segment are valued under the market approach using the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR. We utilize observable inputs which support Level 2 disclosure.

Utilities Segment:

- The commodity contracts for the Utilities, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third party market participant.

Corporate Segment:

- The interest rate swaps are valued using the market valuation approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis (in thousands):

	As of June 30, 2012					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	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 and 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 15.

(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 December 31, 2011						
	Level 1	Level 2	Level 3		Counterparty Netting	Cash Collateral	Total
Assets:							
Commodity derivatives — Oil and Gas							
Options -- Oil	$—	$—	$768	(a)	$5	$—	$773
Basis Swaps -- Oil	—	727	—		—	—	727
Options -- Gas	—	—	—		—	—	—
Basis Swaps -- Gas	—	9,158	—		—	—	9,158
Commodity derivatives —Utilities	—	(9,520)	—		—	19,416	9,896
Money market funds	6,005	—	—		—	—	6,005
Total	$6,005	$365	$768	(a)	$5	$19,416	$26,559
Liabilities:							
Commodity derivatives — Oil and Gas							
Options -- Oil	$—	$—	$1,165	(a)	$5	$—	$1,170
Basis Swaps -- Oil	—	2,200	—		—	—	2,200
Options -- Gas	—	—	—		—	—	—
Basis Swaps -- Gas	—	7	—		—	—	7
Commodity derivatives — Utilities	—	7,156	—		—	—	7,156
Interest rate swaps	—	122,867	—		—	—	122,867
Total	$—	$132,230	$1,165	(a)	$5	$—	$133,400

(a) Of the net beginning balance included as Level 3 for Options - Oil, transfers out of Level 3 included approximately $(0.5) million due to gain (loss) within AOCI and approximately $0.9 million transferred due to the related inputs becoming more observable. Previously, we utilized pricing methodologies developed by our Energy Marketing segment to value our Oil and Gas derivatives. Oil and Gas now obtains available observable inputs including quoted prices traded on active exchanges from multiple sources to value our options. Therefore, options in the Oil and Gas segment have been reclassified from Level 3 to Level 2.

	As of June 30, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$—	$111	$—	$—	$111
Basis Swaps -- Oil	—	552	—	—	—	552
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	6,616	—	—	—	6,616
Commodity derivatives — Utilities	—	(3,266)	—	—	6,254	2,988
Money market funds	6,006	—	—	—	—	6,006
Total	$6,006	$3,902	$111	$—	$6,254	$16,273
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	3,586	—	—	—	3,586
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	117	—	—	—	117
Commodity derivatives — Utilities	—	175	—	—	—	175
Interest rate swaps	—	79,030	—	—	—	79,030
Total	$—	$82,908	$—	$—	$—	$82,908

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements. Further, the amounts do not include net cash collateral on deposit in margin accounts at June 30, 2012, December 31, 2011, and June 30, 2011, 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. 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 13.

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

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

As of December 31, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$8,739	$—
Commodity derivatives	Derivative assets — non-current	1,919	—
Commodity derivatives	Derivative liabilities — current	—	2,559
Commodity derivatives	Derivative liabilities — non-current	—	818
Interest rate swaps	Derivative liabilities — current	—	6,513
Interest rate swaps	Derivative liabilities — non-current	—	20,363
Total derivatives designated as hedges		$10,658	$30,253
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$9,572
Commodity derivatives	Derivative assets — non-current	—	(52)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	7,156
Interest rate swaps	Derivative liabilities — current	—	75,295
Interest rate swaps	Derivative liabilities — non-current	—	20,696
Total derivatives not designated as hedges		$—	$112,667

As of June 30, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$6,609	$—
Commodity derivatives	Derivative assets — non-current	670	—
Commodity derivatives	Derivative liabilities — current	—	2,385
Commodity derivatives	Derivative liabilities — non-current	—	1,318
Interest rate swaps	Derivative liabilities — current	—	6,900
Interest rate swaps	Derivative liabilities — non-current	—	15,788
Total derivatives designated as hedges		$7,279	$26,391
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$3,319
Commodity derivatives	Derivative assets — non-current	—	(53)
Commodity derivatives	Derivative liabilities — current	—	175
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	56,342
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$—	$59,783

A description of our derivative activities is included in Note 13. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income and Comprehensive Income.

Cash Flow Hedges

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

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		$—

Three Months Ended June 30, 2011

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective

	Portion)	Portion)	Portion)	Portion)	Portion)
Interest rate swaps	$(4,768)	Interest expense	$(1,919)		$—
Commodity derivatives	3,772	Revenue	302		—
Total	$(996)		$(1,617)		$—

29

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		$—

Six Months Ended June 30, 2011

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	$(4,470)	Interest expense	$(3,811)		$—
Commodity derivatives	(311)	Revenue	1,333		—
Total	$(4,781)		$(2,478)		$—

Derivatives Not Designated as Hedge Instruments

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

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)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$(7,827)	$(2,362)
Interest rate swaps - realized	Interest expense	(3,352)	(6,704)
		$(11,179)	$(9,066)

30

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	June 30, 2012		December 31, 2011		June 30, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$40,110	$40,110	$21,628	$21,628	$21,971	$21,971
Restricted cash and equivalents [(a)]	$4,772	$4,772	$9,254	$9,254	$3,710	$3,710
Notes payable [(a)]	$225,000	$225,000	$345,000	$345,000	$380,000	$380,000
Long-term debt, including current maturities [(b)]	$1,272,481	$1,460,723	$1,282,882	$1,464,289	$1,187,196	$1,313,052

(a) Fair value approximates carrying value due to short-term maturities 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.

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

Cash and Cash Equivalents

Included in cash and cash equivalents are cash, overnight repurchase agreement accounts, money market funds and term deposits. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal. The carrying amount for cash and cash equivalents approximates fair value due to the short-term maturity of these instruments.

Restricted Cash and Equivalents

Restricted cash and equivalents represent cash and uninsured term deposits.

Notes Payable

The carrying amounts of our notes payable approximate fair value due to their variable interest rates with short reset periods.

Long-term Debt

Our debt instruments are marked to fair value using the market valuation approach. The fair value for our fixed rate debt instruments is estimated based on quoted market prices and yields for debt instruments having similar maturities and debt ratings. The carrying amounts of our variable rate debt approximate fair value due to the variable interest rates with short reset periods.

(16) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

(17) 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. 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.

(18) DISCONTINUED OPERATIONS

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds on the date of the sale were approximately $166.3 million, subject to final post-closing adjustments. The proceeds represent $108.8 million received from the buyer and $57.5 million cash retained from Enserco prior to closing.

Pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments totaling $7.2 million. We contested this proposed adjustment and estimated the amount owed at $1.3 million, which is accrued for in the accompanying financial statements. If we do not reach a negotiated agreement with the buyer regarding the purchase price adjustment, resolution would occur through the dispute resolution provision of the Stock Purchase Agreement.

The accompanying Condensed Consolidated Financial Statements have been classified to reflect Enserco as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification.

Operating results of the Energy Marketing segment included in Income (loss) from discontinued operations, net of tax on the accompanying Condensed Consolidated Statements of Income and Comprehensive Income were as follows (in thousands):

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2012	June 30, 2011	June 30, 2012	June 30, 2011
Revenue	$—	$12,476	$(604)	$14,941
Pre-tax income (loss) from discontinued operations	$(475)	$6,083	$(6,311)	$2,909
Pre-tax gain (loss) on sale	(1,334)	—	(3,787)	—
Income tax (expense) benefit	649	(2,037)	3,454	(1,021)
Income (loss) from discontinued operations, net of tax [(a)]	$(1,160)	$4,046	$(6,644)	$1,888

(a) Includes transaction related costs, net of tax, of $0.3 million and $2.5 million for three and six months ended June 30, 2012, respectively.

Indirect corporate costs and inter-segment interest expenses after-tax totaling $0 and $0.5 million for the three months ended June 30, 2012 and 2011, respectively, and $1.6 million and $1.0 million for the six months ended June 30, 2012 and 2011, respectively, are reclassified from the Energy Marketing segment to the Corporate segment in continuing operations on the accompanying Condensed Consolidated Statements of Income and Comprehensive Income.

Net assets of the Energy Marketing segment included in Assets/Liabilities of discontinued operations in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands) as of:

	December 31, 2011	June 30, 2011
Other current assets	$280,221	$290,990
Derivative assets, current and non-current	52,859	57,563
Property, plant and equipment, net	5,828	6,126
Goodwill	1,435	1,435
Other non-current assets	508	2,555
Other current liabilities	(132,951)	(148,759)
Derivative liabilities, current and non-current	(26,084)	(28,898)
Other non-current liabilities	(14,894)	(5,066)
Net assets	$166,922	$175,946

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*	Oil and Gas Power Generation Coal Mining

* In February 2012, we sold the stock of Enserco, our Energy Marketing segment, through a stock purchase agreement to a third party buyer and therefore we now classify the segment as discontinued operations.

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,500 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 34,800 natural gas customers in Wyoming. Our Gas Utilities serve approximately 528,800 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Oil and Gas, Power Generation and Coal Mining segments. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy principally to other utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities. Our Oil and Gas segment principally 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 gas utilities is November through March, and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2012 and 2011, and our financial condition as of June 30, 2012, December 31, 2011, and June 30, 2011 are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.
See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 62.

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. Information has been revised to remove information related to the operations of our Energy Marketing segment, now classified as discontinued operations, as a result of the sale of Enserco on February 29, 2012.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. Loss from continuing operations for the three months ended June 30, 2012 was $12.3 million, or $0.28 per share, compared to Income from continuing operations of $3.7 million, or $0.09 per share, reported for the same period in 2011. The 2012 Loss from continuing operations included a $10.1 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps and a non-cash after-tax ceiling test impairment of $17.3 million relating to our Oil and Gas segment. The 2011 Income from continuing operations included a $5.1 million after-tax unrealized mark-to-market gain on the same interest rate swaps.

Net loss for the three months ended June 30, 2012 was $13.5 million, or $0.31 per share, compared to Net income of $7.8 million, or $0.19 per share, for the same period in 2011.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. Income from continuing operations for the six months ended June 30, 2012 was $22.9 million, or $0.52 per share, compared to Income from continuing operations of $32.8 million, or $0.82 per share, reported for the same period in 2011. The 2012 Income from continuing operations included a $2.3 million non-cash after-tax unrealized mark-to-market loss on certain 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. The 2011 Income from continuing operations included a $1.5 million after-tax unrealized mark-to-market loss on the same interest rate swaps.

Net income for the six months ended June 30, 2012 was $16.3 million, or $0.37 per share, compared to $34.7 million, or $0.87 per share, for the same period in 2011.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue						
Utilities	$220,120	$239,463	$(19,343)	$559,811	$617,998	$(58,187)
Non-regulated Energy	52,482	42,158	10,324	108,743	83,179	25,564
Intercompany eliminations	(30,239)	(20,972)	(9,267)	(60,340)	(39,693)	(20,647)
	$242,363	$260,649	$(18,286)	$608,214	$661,484	$(53,270)
Net income (loss)						
Electric Utilities	$14,159	$8,614	$5,545	$22,905	$18,863	$4,042
Gas Utilities	1,159	4,440	(3,281)	16,366	23,703	(7,337)
Utilities	15,318	13,054	2,264	39,271	42,566	(3,295)
Oil and Gas [(a)]	(19,621)	(79)	(19,542)	(19,608)	(794)	(18,814)
Power Generation	3,926	548	3,378	10,840	1,734	9,106
Coal Mining	1,234	(381)	1,615	2,234	(1,679)	3,913
Non-regulated Energy	(14,461)	88	(14,549)	(6,534)	(739)	(5,795)
Corporate and eliminations [(b)]	(13,180)	(9,436)	(3,744)	(9,789)	(9,053)	(736)
Income from continuing operations	(12,323)	3,706	(16,029)	22,948	32,774	(9,826)
Income (loss) from discontinued operations, net of tax	(1,160)	4,046	(5,206)	(6,644)	1,888	(8,532)
Net income (loss)	$(13,483)	$7,752	$(21,235)	$16,304	$34,662	$(18,358)

(a) Net income (loss) for 2012 includes a $17.3 million non-cash after-tax ceiling test impairment. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b) Financial results of our Energy Marketing segment have been classified as discontinued operations. Certain indirect corporate costs and inter-segment expenses previously charged to our Energy Marketing segment are reclassified to continuing operations and are included in the Corporate segment. See Note 18 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Business Group highlights for 2012 include:

Utilities Group

- On June 18, 2012, the WPSC approved a stipulation and agreement for Cheyenne Light resulting in an annual revenue increase of $2.7 million for electric customers and $1.6 million for gas customers effective July 1, 2012. The settlement included a return on equity of 9.6% with a capital structure of 54% equity and 46% debt.

- Year-to-date utility results were unfavorably impacted by warm weather, particularly at the Gas Utilities. During 2012, we experienced the warmest March on record for our jurisdictions. Heating degree days year-to-date were 17% and 22% lower than weighted average norms for our Electric and Gas Utilities, respectively. When compared to colder than normal weather during the same period in 2011, heating degree days were 24% and 26% lower than the same period in 2011 for our Electric Utilities and our Gas Utilities, respectively. The warm weather continued into the summer months, and cooling degree days quarter-to-date for our Electric Utilities were on average 109% greater than weighted average normal weather for the quarter ended June 30, 2012 and on average 81% higher than the same period in the prior year.

- Colorado Electric's new $230 million, 180 MW power plant near Pueblo, Colorado began commercial operations and started serving utility customers on January 1, 2012. New rates were effective January 1, 2012, providing an additional $20.5 million in gross margins at Colorado Electric for the six months ended June 30, 2012.

- On July 31, 2012, Cheyenne Light and Black Hills Power received approval from the WPSC for a CPCN authorizing the construction, operation and maintenance of a new $237 million, 132 megawatt natural gas-fired electric generating facility and related gas and electric transmission in Cheyenne, Wyoming. On July 13, 2012, a Stipulation and Agreement among the joint applicants and the intervenor was filed with the WPSC including provisions for a construction work-in-progress rate rider. Use of the CWIP rider would allow a rate of return during construction, eliminating the usual allowance for funds used during construction, and reducing the total construction cost from $237 million to $222 million. The WPSC noted the Stipulation and Agreement in the CPCN hearing on July 31, 2012,without approving the CWIP rider and indicating its preference to consider the rider and total construction cost in a separate proceeding.

- Colorado Electric is progressing on construction of a 29 MW wind turbine project as part of its plan to meet Colorado's Renewable Energy Standard. Colorado Electric's 50% share of this project will cost approximately $26.5 million and the project is expected to begin serving Colorado Electric customers no later than December 31, 2012. Our 50% share of the total expenditures on the project was $20.1 million as of June 30, 2012.

- On April 13, 2012, the CPUC issued its final order denying Colorado Electric's request for a CPCN to construct a third utility-owned, 88 MW natural gas-fired turbine at the existing Pueblo Airport generating location. Colorado Electric retains the right under the Colorado Clean Air – Clean Jobs Act to own the 42 megawatts of replacement generation for the W.N. Clark plant that is required to be retired on or before December 13, 2013. Colorado Electric filed an electric resource plan on July 30, 2012 that proposed building a 40 MW, simple-cycle, gas-fired turbine as the alternative replacement resource for the W.N. Clark plant. We have not yet filed a CPCN requesting approval to construct this gas-fired facility.

- Colorado Gas filed a request with the CPUC on June 4, 2012 for an increase in annual gas revenues of $1.0 million to recover capital investments made in its gas system since January 2008.

Non-regulated Energy Group

- Our Coal Mining segment received all necessary permits and approval for a revised mine plan which will relocate mining operations to an area in the mine with lower overburden, reducing overall mining costs for the next several years. The new mine plan went into effect during the second quarter of 2012.

- 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.

- Colorado IPP's new $261 million, 200 MW power plant near Pueblo, Colorado began serving customers on January 1, 2012, with its output sold under a 20-year power purchase agreement to Colorado Electric.

Corporate

- On June 24, 2012, we extended for one year our $150 million term loan under favorable terms of 1.10% over LIBOR.

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On February 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring February 1, 2017 at favorable terms. Deferred financing costs of $1.5 million relating to the previous credit facility were written off during the first quarter of 2012.

We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $3.5 million for the six months ended June 30, 2012 compared to a $2.4 million unrealized mark-to-market loss on these swaps for the same period in 2011.

Discontinued Operations

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds on the date of the sale were approximately $166.3 million, subject to final post-closing adjustments.

Pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments totaling $7.2 million. We contested this proposed adjustment and estimated the amount owed at $1.3 million, which is accrued for in the accompanying financial statements. If we do not reach a negotiated agreement with the buyer regarding the purchase price adjustment, resolution would occur through the dispute resolution provision of the Stock Purchase Agreement.

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,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue — electric	$144,985	$132,978	$12,007	$291,266	$267,848	$23,418
Revenue — Cheyenne Light gas	4,749	6,563	(1,814)	17,637	19,962	(2,325)
Total revenue	149,734	139,541	10,193	308,903	287,810	21,093
Fuel, purchased power and cost of gas — electric	59,523	66,254	(6,731)	125,121	131,932	(6,811)
Purchased gas — Cheyenne Light gas	1,923	3,484	(1,561)	10,041	11,880	(1,839)
Total fuel, purchased power and cost of gas	61,446	69,738	(8,292)	135,162	143,812	(8,650)
Gross margin — electric	85,462	66,724	18,738	166,145	135,916	30,229
Gross margin — Cheyenne Light gas	2,826	3,079	(253)	7,596	8,082	(486)
Total gross margin	88,288	69,803	18,485	173,741	143,998	29,743
Operations and maintenance	36,866	34,156	2,710	76,096	71,270	4,826
Depreciation and amortization	18,695	13,006	5,689	37,627	25,830	11,797
Total operating expenses	55,561	47,162	8,399	113,723	97,100	16,623
Operating income	32,727	22,641	10,086	60,018	46,898	13,120
Interest expense, net	(12,322)	(10,107)	(2,215)	(25,542)	(20,051)	(5,491)
Other income (expense), net	291	(53)	344	1,009	356	653
Income tax benefit (expense)	(6,537)	(3,867)	(2,670)	(12,580)	(8,340)	(4,240)
	$14,159	$8,614	$5,545	$22,905	$18,863	$4,042

Income (loss) from continuing operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue - Electric (in thousands)	2012	2011	2012	2011
Residential:				
Black Hills Power	$12,633	$12,773	$28,109	$29,943
Cheyenne Light	7,022	7,026	15,492	15,097
Colorado Electric	21,042	19,155	43,658	39,591
Total Residential	40,697	38,954	87,259	84,631
Commercial:				
Black Hills Power	18,804	17,759	35,612	35,073
Cheyenne Light	15,386	13,495	29,343	26,038
Colorado Electric	21,570	18,373	40,697	34,958
Total Commercial	55,760	49,627	105,652	96,069
Industrial:				
Black Hills Power	7,063	6,464	13,083	12,228
Cheyenne Light	3,243	2,944	6,312	5,556
Colorado Electric	9,981	8,567	19,213	16,434
Total Industrial	20,287	17,975	38,608	34,218
Municipal:				
Black Hills Power	887	783	1,585	1,517
Cheyenne Light	472	455	898	846
Colorado Electric	3,948	3,186	6,612	6,122
Total Municipal	5,307	4,424	9,095	8,485
Total Retail Revenue - Electric	122,051	110,980	240,614	223,403
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	4,370	4,370	9,275	8,990
Off-system Wholesale:				
Black Hills Power	6,459	7,442	17,732	14,395
Cheyenne Light	1,967	2,580	4,480	5,467
Colorado Electric [(a)]	177	—	410	—
Total Off-system Wholesale [(a)]	8,603	10,022	22,622	19,862
Other Revenue:				
Black Hills Power	8,156	6,507	15,246	13,146
Cheyenne Light	427	567	1,039	1,256
Colorado Electric	1,378	532	2,470	1,191
Total Other Revenue	9,961	7,606	18,755	15,593
Total Revenue - Electric	$144,985	$132,978	$291,266	$267,848

(a) Off-system sales revenue during 2011 was deferred until a sharing mechanism was approved by the CPUC in December 2011, and recognition of 25% of the revenue commenced January 2, 2012. As a result, Colorado Electric deferred \$3.5 million and \$6.4 million in off-system revenue during the three and six months ended June 30, 2011.

Quantities Generated and Purchased (in MWh)	Three Months Ended June 30, 2012	2011	Six Months Ended June 30, 2012	2011
Generated —				
Coal-fired:				
Black Hills Power	369,049	386,006	868,841	823,844
Cheyenne Light	154,324	169,195	281,477	340,566
Colorado Electric	58,585	71,236	115,892	127,911
Total Coal-fired	581,958	626,437	1,266,210	1,292,321
Gas and Oil-fired:				
Black Hills Power	6,216	1,147	6,579	2,171
Cheyenne Light	—	—	—	—
Colorado Electric	19,948	30	21,580	30
Total Gas and Oil-fired	26,164	1,177	28,159	2,201
Total Generated:				
Black Hills Power	375,265	387,153	875,420	826,015
Cheyenne Light	154,324	169,195	281,477	340,566
Colorado Electric	78,533	71,266	137,472	127,941
Total Generated	608,122	627,614	1,294,369	1,294,522
Purchased —				
Black Hills Power	432,723	401,218	947,257	776,830
Cheyenne Light	181,408	179,079	413,027	376,248
Colorado Electric	409,242	486,052	810,369	968,837
Total Purchased	1,023,373	1,066,349	2,170,653	2,121,915
Total Generated and Purchased:				
Black Hills Power	807,988	788,371	1,822,677	1,602,845
Cheyenne Light	335,732	348,274	694,504	716,814
Colorado Electric	487,775	557,318	947,841	1,096,778
Total Generated and Purchased	1,631,495	1,693,963	3,465,022	3,416,437

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantity Sold (in MWh)	2012	2011	2012	2011
Residential:				
Black Hills Power	106,557	107,683	256,985	282,083
Cheyenne Light	56,440	58,532	128,277	131,410
Colorado Electric	136,677	138,644	290,729	295,999
Total Residential	299,674	304,859	675,991	709,492
Commercial:				
Black Hills Power	181,281	167,649	351,374	345,886
Cheyenne Light	158,346	143,645	308,285	289,244
Colorado Electric	184,734	180,168	350,125	345,902
Total Commercial	524,361	491,462	1,009,784	981,032
Industrial:				
Black Hills Power	115,024	105,861	210,759	194,610
Cheyenne Light	44,155	42,642	88,929	83,470
Colorado Electric	97,192	91,188	178,434	175,097
Total Industrial	256,371	239,691	478,122	453,177
Municipal:				
Black Hills Power	8,843	7,739	16,411	16,041
Cheyenne Light	2,128	2,150	4,710	4,594
Colorado Electric	35,019	32,079	60,188	59,826
Total Municipal	45,990	41,968	81,309	80,461
Total Retail Quantity Sold	1,126,396	1,077,980	2,245,206	2,224,162
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	72,006	82,253	161,054	172,212
Off-system Wholesale:				
Black Hills Power	295,149	278,086	753,379	520,242
Cheyenne Light	53,911	79,741	120,620	163,926
Colorado Electric	6,063	94,945	8,671	173,448
Total Off-system Wholesale	355,123	452,772	882,670	857,616
Total Quantity Sold:				
Black Hills Power	778,860	749,271	1,749,962	1,531,074
Cheyenne Light	314,980	326,710	650,821	672,644
Colorado Electric	459,685	537,024	888,147	1,050,272
Total Quantity Sold	1,553,525	1,613,005	3,288,930	3,253,990
Losses and Company Use:				
Black Hills Power	29,128	39,100	72,715	71,771
Cheyenne Light	20,752	21,564	43,682	44,170
Colorado Electric	28,090	20,294	59,695	46,506

Total Losses and Company Use	77,970	80,958	176,092	162,447
Total Quantity Sold	1,631,495	1,693,963	3,465,022	3,416,437

Degree Days	Three Months Ended June 30, 2012		2011	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Actual —				
Black Hills Power	748	(27)%	1,190	19%
Cheyenne Light	841	(29)%	1,354	10%
Colorado Electric	405	(36)%	638	(1)%
Cooling Degree Days:				
Actual —				
Black Hills Power	206	108%	56	(45)%
Cheyenne Light	138	176%	30	(29)%
Colorado Electric	423	102%	294	36%

Degree Days	Six Months Ended June 30, 2012		2011	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Black Hills Power	3,459	(18)%	4,897	14%
Cheyenne Light	3,602	(14)%	4,477	2%
Colorado Electric	2,699	(18)%	3,419	4%
Cooling Degree Days:				
Black Hills Power	206	108%	56	(45)%
Cheyenne Light	138	176%	30	(29)%
Colorado Electric	423	102%	294	36%

Electric Utilities Power Plant Availability	Three Months Ended June 30, 2012	2011	Six Months Ended June 30, 2012	2011
Coal-fired plants	81.0% (a)	88.6% (b)	86.0% (a)	89.9% (b)
Other plants	96.4%	89.9% (c)	95.7%	94.3%
Total availability	88.8%	89.0%	90.9%	91.5%

(a) Three 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.
(b) 2011 includes a major overhaul and an unplanned outage at the PacifiCorp operated Wyodak plant.
(c) Reflects a planned major overhaul at Neil Simpson CT.

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,	
	2012	2011	2012	2011
Revenue - Gas (in thousands):				
Residential	$2,955	$4,053	$10,585	$12,031
Commercial	1,209	1,739	5,019	5,546
Industrial	397	580	1,634	1,856
Other Sales Revenue	188	191	399	529
Total Revenue - Gas	$4,749	$6,563	$17,637	$19,962
Gross Margin (in thousands):				
Residential	$2,002	$2,332	$5,228	$5,720
Commercial	551	694	1,724	1,906
Industrial	85	98	249	275
Other Gross Margin	188	(45)	395	181
Total Gross Margin	$2,826	$3,079	$7,596	$8,082
Volumes Sold (Dth):				
Residential	315,571	497,250	1,285,249	1,565,711
Commercial	217,847	302,543	798,787	926,266
Industrial	109,803	140,135	346,943	396,656
Total Volumes Sold	643,221	939,928	2,430,979	2,888,633

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011: Income from continuing operations for the Electric Utilities was $14.2 million for the three months ended June 30, 2012 compared to $8.6 million for the three months ended June 30, 2011 as a result of:

Gross margin increased primarily due to a $10.9 million increase related to rate adjustments that include a return on significant capital investments at Colorado Electric, increased retail margins of $2.5 million on higher quantities sold driven by warmer weather, an increase of $1.8 million from wholesale and transmission margins as a result of increased pricing, and a $0.5 million increase from an Environmental Improvement Cost Recovery Adjustment rider at Black Hills Power.

Operations and maintenance increased primarily due to operating the new generating facility in Pueblo, Colorado and associated increased corporate allocations, and an increase in major maintenance costs from our generating facilities.

Depreciation and amortization increased primarily due to a higher asset base associated with the 180 MW generating facility constructed in Pueblo, Colorado and the capital lease assets associated with the 200 MW generating facility providing capacity and energy from Colorado IPP.

Interest expense, net increased primarily due to interest associated with the financing of the Pueblo generating facility completed in December 2011.

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, 2012 Compared to Six Months Ended June 30, 2011: Income from continuing operations for the Electric Utilities was $22.9 million for the six months ended June 30, 2012 compared to $18.9 million for the six months ended June 30, 2011 as a result of:

Gross margin increased primarily due to a $20.4 million increase related to rate adjustments that include a return on significant capital investments at Colorado Electric, a $2.7 million increase from wholesale and transmission margins from increased pricing, a $0.6 million increase in off-system sales mainly from higher volumes, a $1.2 million increase from an Environmental Improvement Cost Recovery Adjustment rider at Black Hills Power and increased retail margins as a result of a higher quantities sold driven by warmer weather.

Operations and maintenance increased primarily due to costs associated with operating the new generating facility in Pueblo, Colorado and associated increased corporate allocations.

Depreciation and amortization increased primarily due to a higher asset base associated with the 180 MW generating facility constructed in Pueblo, Colorado and the capital lease assets associated with the 200 MW generating facility providing capacity and energy from Colorado IPP.

Interest expense, net increased primarily due to interest associated with financing of the Pueblo generating facility completed in December 2011.

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

Income tax benefit (expense): The effective tax rate increased due to unfavorable state income tax true-up adjustments and the impact of research and development credits not being renewed.

Gas Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Natural gas — regulated	$64,033	$93,598	$(29,565)	$236,202	$316,630	$(80,428)
Other — non-regulated services	6,353	6,324	29	14,706	13,558	1,148
Total revenue	70,386	99,922	(29,536)	250,908	330,188	(79,280)
Natural gas — regulated	25,424	49,956	(24,532)	133,540	199,459	(65,919)
Other — non-regulated services	3,020	3,154	(134)	6,889	6,780	109
Total cost of sales	28,444	53,110	(24,666)	140,429	206,239	(65,810)
Gross margin	41,942	46,812	(4,870)	110,479	123,949	(13,470)
Operations and maintenance	28,483	28,249	234	59,782	62,809	(3,027)
Depreciation and amortization	6,253	5,947	306	12,410	11,968	442
Total operating expenses	34,736	34,196	540	72,192	74,777	(2,585)
Operating income (loss)	7,206	12,616	(5,410)	38,287	49,172	(10,885)
Interest expense, net	(5,749)	(6,339)	590	(12,289)	(13,311)	1,022
Other income (expense), net	73	124	(51)	84	149	(65)
Income tax benefit (expense)	(371)	(1,961)	1,590	(9,716)	(12,307)	2,591
Income (loss) from continuing operations	$1,159	$4,440	$(3,281)	$16,366	$23,703	$(7,337)

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

Revenue (in thousands)	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Residential:				
Colorado	$7,321	$10,749	$29,339	$33,735
Nebraska	13,538	20,663	54,462	79,062
Iowa	11,870	18,593	46,440	66,024
Kansas	7,762	10,568	29,183	38,521
Total Residential	40,491	60,573	159,424	217,342
Commercial:				
Colorado	1,433	2,182	5,627	6,815
Nebraska	3,918	6,385	18,018	26,303
Iowa	4,734	7,802	20,507	28,685
Kansas	1,994	2,944	8,729	12,240
Total Commercial	12,079	19,313	52,881	74,043
Industrial:				
Colorado	594	583	646	698
Nebraska	140	163	429	336
Iowa	449	407	1,194	1,144
Kansas	4,314	6,849	5,236	7,969
Total Industrial	5,497	8,002	7,505	10,147
Transportation:				
Colorado	157	179	503	507
Nebraska	1,672	2,072	5,471	6,431
Iowa	978	827	2,228	2,152
Kansas	1,161	1,125	3,029	3,192
Total Transportation	3,968	4,203	11,231	12,282
Other Sales Revenue:				
Colorado	21	25	50	56
Nebraska	517	511	1,092	1,119
Iowa	141	193	264	319
Kansas	1,319	778	3,755	1,322
Total Other Sales Revenue	1,998	1,507	5,161	2,816
Total Regulated Revenue	64,033	93,598	236,202	316,630
Non-regulated Services	6,353	6,324	14,706	13,558
Total Revenue	$70,386	$99,922	$250,908	$330,188

Gross Margin (in thousands)	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Residential:				
Colorado	$3,141	$3,760	$8,827	$9,880
Nebraska	8,997	10,464	24,588	29,381
Iowa	8,328	10,313	20,523	26,594
Kansas	5,795	6,120	14,915	16,198
Total Residential	26,261	30,657	68,853	82,053
Commercial:				
Colorado	503	613	1,419	1,645
Nebraska	1,740	2,136	5,623	6,976
Iowa	2,036	2,433	5,833	6,596
Kansas	1,108	1,189	3,278	3,725
Total Commercial	5,387	6,371	16,153	18,942
Industrial:				
Colorado	172	127	202	163
Nebraska	44	41	105	91
Iowa	45	48	116	138
Kansas	772	761	994	992
Total Industrial	1,033	977	1,417	1,384
Transportation:				
Colorado	157	178	504	506
Nebraska	1,672	2,072	5,471	6,431
Iowa	978	827	2,228	2,152
Kansas	1,161	1,125	3,029	3,192
Total Transportation	3,968	4,202	11,232	12,281
Other Sales Margins:				
Colorado	21	25	50	56
Nebraska	518	511	1,093	1,119
Iowa	142	193	265	319
Kansas	1,279	706	3,600	1,017
Total Other Sales Margins	1,960	1,435	5,008	2,511
Total Regulated Gross Margin	38,609	43,642	102,663	117,171
Non-regulated Services	3,333	3,170	7,816	6,778
Total Gross Margin	$41,942	$46,812	$110,479	$123,949

Volumes Sold (in Dth)	Three Months Ended June 30, 2012	2011	Six Months Ended June 30, 2012	2011
Residential:				
Colorado	797,696	1,127,379	3,401,097	3,847,384
Nebraska	998,527	1,772,388	5,351,344	7,842,625
Iowa	854,889	1,607,488	5,006,355	6,920,778
Kansas	498,802	818,677	3,158,476	4,249,556
Total Residential	3,149,914	5,325,932	16,917,272	22,860,343
Commercial:				
Colorado	179,454	253,822	706,248	835,518
Nebraska	509,760	748,867	2,290,391	3,091,977
Iowa	669,018	1,042,988	2,896,813	3,888,734
Kansas	226,476	324,680	1,219,481	1,627,611
Total Commercial	1,584,708	2,370,357	7,112,933	9,443,840
Industrial:				
Colorado	140,017	99,708	150,569	115,322
Nebraska	24,801	22,946	65,702	36,194
Iowa	93,817	68,662	222,959	178,463
Kansas	1,280,464	1,312,270	1,469,361	1,508,598
Total Industrial	1,539,099	1,503,586	1,908,591	1,838,577
Transportation:				
Colorado	146,703	183,494	508,576	528,665
Nebraska	5,448,471	6,688,435	13,589,365	12,636,481
Iowa	4,492,459	4,026,034	9,679,955	9,579,099
Kansas	3,286,586	2,940,539	7,646,507	7,380,809
Total Transportation	13,374,219	13,838,502	31,424,403	30,125,054
Other Volumes:				
Colorado	—	—	—	—
Nebraska	—	—	—	—
Iowa	—	—	—	—
Kansas	7,503	17,081	31,953	62,066
Total Other Volumes	7,503	17,081	31,953	62,066
Total Volumes Sold	19,655,443	23,055,458	57,395,152	64,329,880

Heading Degree Days:	Three Months Ended June 30, 2012 Actual	Variance From Normal	Six Months Ended June 30, 2012 Actual	Variance From Normal
Colorado	552	(40)%	2,902	(22)%
Nebraska	370	(36)%	2,770	(23)%
Iowa	614	(21)%	3,413	(20)%
Kansas [(a)]	291	(39)%	2,331	(21)%
Combined [(b)]	490	(31)%	2,922	(22)%

Heating Degree Days:	Three Months Ended June 30, 2011 Actual	Variance From Normal	Six Months Ended June 30, 2011 Actual	Variance From Normal
Colorado	840	(11)%	3,601	(6)%
Nebraska	585	2%	3,866	2%
Iowa	851	7%	4,545	1%
Kansas [(a)]	406	(10)%	3,031	1%
Combined [(b)]	726	1%	4,069	—%

(a) Our gross margin in Kansas utilizes normal degree days due to an approved weather normalization mechanism.
(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas which has an approved weather normalization mechanism.

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

Results of Operations for the Gas Utilities for the Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011: Income from continuing operations for the Gas Utilities was $1.2 million for the three months ended June 30, 2012 compared to Income from continuing operations of $4.4 million for the three months ended June 30, 2011 as a result of:

Gross margin decreased primarily due to a $2.0 million impact from milder weather compared to the same period in the prior year. Heating degree days were 33% lower for the three months ended June 30, 2012 compared to the same period in the prior year and 31% lower than normal. A reclassification accounting adjustment was made in the current year recording $1.3 million against gross margin that in prior year is included in operations and maintenance.

Operations and maintenance is comparable to the prior year reflecting that the same period in the prior year included a favorable property tax true up adjustment of $0.8 million offset by a reclassification accounting adjustment that was made in the current year recording $1.3 million of operating costs in gross margin.

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

Interest expense, net decreased primarily due to lower interest rates.

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

Income tax benefit (expense): The effective tax rate decreased as a result of a favorable true-up adjustment that had a more pronounced impact due to significantly lower pre-tax net income when compared to 2011. Prior year also realized a favorable true up adjustment, but its impact on the effective tax rate was less pronounced due to significantly higher pre-tax net income when compared to 2012.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011: Income from continuing operations for the Gas Utilities was $16.4 million for the six months ended June 30, 2012 compared to Income from continuing operations of $23.7 million for the six months ended June 30, 2011 as a result of:

Gross margin decreased primarily due to a $9.3 million impact from milder weather compared to the same period in the prior year. Heating degree days were 28% lower for the six months ended June 30, 2012 compared to the same period in the prior year and 22% lower than normal. A reclassification accounting adjustment was made in the current year recording $4.0 million against gross margin that in prior year is included in operations and maintenance.

Operations and maintenance decreased primarily due to lower bad debt costs and cost efficiencies and a reclassification accounting adjustment that was made in the current year recording $4.0 million of operating costs in gross margin.

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

Interest expense, net decreased primarily due to lower interest rates.

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 an unfavorable state true-up adjustment. Additionally, the 2011 period was favorably impacted as a result of federal income tax related research and development credits and a flow-through tax adjustment involving Iowa Gas.

Regulatory Matters — Utilities Group

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

				Revenue	Revenue		Approved Capital Structure	
	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Equity	Debt
Nebraska Gas (1)	Gas	12/2009	9/2010	$12.1	$8.3	10.1%	52.0%	48.0%
Iowa Gas (4)	Gas	6/2010	2/2011	$4.7	$3.4	Global Settlement	Global Settlement	Global Settlement
Colorado Electric (4)	Electric	4/2011	1/2012	$40.2	$28.0	9.8% - 10.2%	49.1%	50.9%
Cheyenne Light (2)	Electric/Gas	12/2011	7/2012	$8.5	$4.3	9.6%	54.0%	46.0%
Black Hills Power (4)	Electric	1/2011	6/2011	Not Applicable	$3.1	Not Applicable	Not Applicable	Not Applicable
Colorado Gas (3)	Gas	6/2012	Pending	$1.0	Pending	Pending	Pending	Pending

(1) The Nebraska Public Advocate filed an appeal with the District Court related to the rate case decision which has been denied. Subsequently, the Nebraska Public Advocate filed a notice of appeal in the Court of Appeals. On March 20, 2012, the Court of Appeals affirmed the earlier decision of the District Court. The Nebraska Public Advocate petitioned the Nebraska Supreme Court to hear an appeal which was denied.

(2) Cheyenne Light filed requests on December 1, 2011 for electric and natural gas revenue increases with the WPSC seeking a $5.9 million increase in annual electric revenue and a $2.6 million increase in annual natural gas revenue. On June 18, 2012, the WPSC approved a settlement agreement resulting in annual revenue increases of $2.7 million for electric customers and $1.6 million for gas customers effective July 1, 2012. The cost adjustment mechanism relating to transmission, fuel and purchased power costs was modified to eliminate the $1.0 million threshold and changed the sharing mechanism to 85% to the customer for these cost adjustment mechanisms. The agreement approved a return on equity of 9.6% with a capital structure of 54% equity and 46% debt.

(3) Colorado Gas filed a request with the CPUC on June 4, 2012 for an increase in annual gas revenues of $1.0 million to recover capital investments made in its gas system since January 2008.

(4) These rate settlements were the most recent for the jurisdiction and were previously described in our 2011 Annual Report on Form 10-K.

Non-regulated Energy Group

We report three segments within our Non-regulated Energy Group: Oil and Gas, Coal Mining and Power Generation. For more than 15 years, we also owned and operated Enserco, an energy marketing business that engages in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. We sold Enserco on February 29, 2012, which resulted in our Energy Marketing segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations.

Power Generation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue	$18,734	$7,780	$10,954	$38,361	$15,400	$22,961
Operations and maintenance	7,566	4,091	3,475	14,698	8,279	6,419
Depreciation and amortization	1,116	1,040	76	2,230	2,104	126
Total operating expense	8,682	5,131	3,551	16,928	10,383	6,545
Operating income	10,052	2,649	7,403	21,433	5,017	16,416
Interest expense, net	(3,972)	(1,835)	(2,137)	(8,715)	(3,626)	(5,089)
Other (expense) income	9	21	(12)	14	1,225	(1,211)
Income tax (expense) benefit	(2,163)	(287)	(1,876)	(1,892)	(882)	(1,010)
Income (loss) from continuing operations	$3,926	$548	$3,378	$10,840	$1,734	$9,106

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,	
	2012	2011	2012	2011
Contracted power plant fleet availability:				
Coal-fired plant	99.2 %	99.5 %	99.6 %	99.8 %
Natural gas-fired plants	98.9 %	100.0 %	99.2 %	100.0 %
Total availability	99.0 %	99.7 %	99.3 %	99.8 %

Results of Operations for Power Generation for the Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011: Income from continuing operations for the Power Generation segment was $3.9 million for the three months ended June 30, 2012 compared to Income from continuing operations of $0.5 million for the same period in 2011 as a result of:

Revenue increased due to commencement of commercial operation of our new 200 MW generating facility in Pueblo, Colorado on January 1, 2012.

Operations and maintenance increased primarily due to the costs to operate and corporate allocations relating to our new 200 MW generating facility in Pueblo, Colorado, which began serving customers on January 1, 2012.

Depreciation and amortization were consistent with the same period in the prior year. The new generating facility's PPA to supply capacity and energy to Colorado Electric 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 increased due to the decrease in capitalized interest as a result of completing construction on our new generating facility in Pueblo, Colorado.

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, 2012 Compared to Six Months Ended June 30, 2011: Income from continuing operations for the Power Generation segment was $10.8 million for the six months ended June 30, 2012 compared to Income from continuing operations of $1.7 million for the same period in 2011 as a result of:

Revenue increased due to commencement of commercial operation of our new 200 MW generating facility in Pueblo, Colorado on January 1, 2012.

Operations and maintenance increased primarily due to the costs to operate and corporate allocations relating to our new 200 MW generating facility in Pueblo, Colorado on January 1, 2012.

Depreciation and amortization were consistent with the same period in the prior year. The new generating facility's PPA to supply capacity and energy to Colorado Electric 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 increased due to the decrease in capitalized interest as a result of the completion of construction of our generating facility in Pueblo, Colorado.

Other (expense) income, net in 2011 included earnings from our partnership investment in certain Idaho generating facilities and a gain on sale of our ownership interest in the partnership which did not reoccur in 2012.

Income tax (expense) benefit: The effective tax rate was impacted by a favorable state tax true-up that included certain tax credits. Such credits are the result of meeting certain applicable state requirements including the ability to utilize these tax credits. The incentives pertain to qualified plant expenditures related to investment and research and development.

Coal Mining

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue	$13,127	$15,540	$(2,413)	$28,116	$31,035	$(2,919)
Operations and maintenance	9,883	13,011	(3,128)	21,361	27,583	(6,222)
Depreciation, depletion and amortization	2,955	4,595	(1,640)	6,651	9,213	(2,562)
Total operating expenses	12,838	17,606	(4,768)	28,012	36,796	(8,784)
Operating income (loss)	289	(2,066)	2,355	104	(5,761)	5,865
Interest income, net	403	936	(533)	1,158	1,896	(738)
Other income	646	549	97	1,527	1,118	409
Income tax benefit (expense)	(104)	200	(304)	(555)	1,068	(1,623)
Income (loss) from continuing operations	$1,234	$(381)	$1,615	$2,234	$(1,679)	$3,913

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Tons of coal sold	983	1,235	2,086	2,605
Cubic yards of overburden moved	2,280	2,933	4,922	6,388

Results of Operations for Coal Mining for the Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011: Income from continuing operations for the Coal Mining segment was $1.2 million for the three months ended June 30, 2012 compared to Loss from continuing operations of $0.4 million for the same period in 2011, as a result of:

Revenue decreased primarily due to a 20% decrease in tons sold. This decrease was due to the December 2011 expiration of an unprofitable long-term train load-out contract which represented approximately 29% of our tons sold in 2011. Additionally, tons sold decreased due to a planned and unplanned outage at Neil Simpson II. These decreases were partially offset by increased volumes sold to the Wyodak plant that experienced an outage in 2011. Approximately 50% of our coal production was sold under contracts that include price adjustments based on actual mining cost increases.

Operations and maintenance decreased primarily due to a 20% reduction in tons sold related to an unprofitable train-load out contract that expired at the end of 2011 reducing overburden moved, and mining efficiencies.

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

Interest income, net decreased primarily due to a decrease in inter-company notes receivable upon payment of a dividend to our parent.

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

Income tax benefit (expense): The change in the effective tax rate was primarily due to the impact of percentage depletion.

Results of Operations for Coal Mining for the Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011: Income from continuing operations for the Coal Mining segment was $2.2 million for the six months ended June 30, 2012 compared to Loss from continuing operations of $1.7 million for the same period in 2011, as a result of:

Revenue decreased primarily due to a 20% decrease in tons sold. This decrease was due to the December 2011 expiration of an unprofitable long-term train load-out contract .which represented approximately 29% of our tons sold in 2011. Additionally, tons sold decreased due to a planned and unplanned outage at Neil Simpson II and planned and extended outage at the Wygen II facility. These decreases were partially offset by increased volumes sold to the Wyodak plant that experienced an outage in 2011. Approximately 50% of our coal production was sold under contracts that include price adjustments based on actual mining cost increases.

Operations and maintenance decreased primarily due to a 20% reduction in tons sold related to an unprofitable train-load out contract that expired at the end of 2011, reducing overburden moved, and mining efficiencies.

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

Interest income, net decreased primarily due to a decrease in inter-company notes receivable upon payment of a dividend to our parent.

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

Income tax benefit (expense): The change in the effective tax rate was primarily due to the impact of percentage depletion.

Oil and Gas

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Variance	2012	2011	Variance
	(in thousands)					
Revenue	$20,621	$18,838	$1,783	$42,266	$36,744	$5,522
Operations and maintenance	10,338	10,187	151	21,172	20,754	418
Depreciation, depletion and amortization	13,033	7,602	5,431	22,356	14,923	7,433
Impairment of long-lived assets	26,868	—	26,868	26,868	—	26,868
Total operating expenses	50,239	17,789	32,450	70,396	35,677	34,719
Operating income (loss)	(29,618)	1,049	(30,667)	(28,130)	1,067	(29,197)
Interest expense	(1,165)	(1,389)	224	(2,770)	(2,772)	2
Other income (expense), net	87	88	(1)	116	(97)	213
Income tax benefit (expense)	11,075	173	10,902	11,176	1,008	10,168
Income (loss) from continuing operations	$(19,621)	$(79)	$(19,542)	$(19,608)	$(794)	$(18,814)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Production:				
Bbls of oil sold	155,362	100,901	300,839	204,451
Mcf of natural gas sold	2,451,811	2,106,121	4,840,286	4,117,288
Gallons of NGL sold	837,626	988,819	1,652,211	1,853,259
Mcf equivalent sales	3,503,644	2,852,787	6,881,350	5,608,745

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Average price received: (a)				
Oil/Bbl	$76.71	$79.53	$77.33	$73.10
Gas/Mcf	$3.12	$4.29	$3.36	$4.47
NGL/gallon	$0.74	$1.01	$0.84	$0.97
Depletion expense/Mcfe	$3.47	$2.40	$2.98	$2.38

(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, 2012				Three Months Ended June 30, 2011			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.06	$0.19	$0.23	$1.48	$1.21	$0.35	$0.55	$2.11
Piceance	0.52	0.32	0.10	0.94	0.83	0.76	(0.36)	1.23
Powder River	1.60	—	1.08	2.68	1.42	—	1.38	2.80
Williston	0.53	—	1.29	1.82	0.50	—	1.48	1.98
All other properties	1.59	—	0.18	1.77	1.23	—	0.04	1.27
Total weighted average	$1.00	$0.13	$0.54	$1.67	$1.15	$0.23	$0.63	$2.01

	Six Months Ended June 30, 2012				Six Months Ended June 30, 2011			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.02	$0.25	$0.29	$1.56	$1.23	$0.41	$0.55	$2.19
Piceance	0.23	0.41	0.13	0.77	0.76	0.78	(0.06)	1.48
Powder River	1.49	—	1.20	2.69	1.36	—	1.33	2.69
Williston	0.61	—	1.27	1.88	0.38	—	1.49	1.87
All other properties	1.63	—	0.13	1.76	1.43	—	0.21	1.64
Total weighted average	$0.94	$0.17	$0.57	$1.68	$1.17	$0.25	$0.68	$2.10

Results of Operations for Oil and Gas for the Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011: Loss from continuing operations for the Oil and Gas segment was $19.6 million for the three months ended June 30, 2012 compared to Loss from continuing operations of $0.1 million for the same period in 2011 as a result of:

Revenue increased primarily due to increased production. A 54% increase in crude oil sales, due primarily to activities from new wells in the company’s ongoing drilling program in the Bakken shale formation, was partially offset by a 4% decrease in the average price received for crude oil sold. A 14% increase in natural gas and NGL volumes, due primarily to the completion of three Mancos formation test wells in the San Juan and Piceance Basins, was partially offset by a 27% decrease in average price received for natural gas.

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

Depreciation, depletion and amortization increase primarily reflects a $3.4 million year-to-date impact of adjusting our expected 2012 reserve additions due to the deferred drilling activities in the San Juan Mancos formation, as well as higher cost reserves associated with our Bakken activities.

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

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 (expense) benefit: For 2012, the benefit generated by percentage depletion had a significantly reduced impact on the effective tax rate compared to the same period in 2011.

Results of Operations for Oil and Gas for the Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011: Loss from continuing operations for the Oil and Gas segment was $19.6 million for the six months ended June 30, 2012 compared to Loss from continuing operations of $0.8 million for the same period in 2011 as a result of:

Revenue increased primarily due to a 47% increase in crude oil volume sold along with a 6% increase in the average price received for crude oil sales. Crude oil production increases reflect volumes from new wells in our ongoing drilling program in the Bakken shale formation. A 16% increase in natural gas and NGL volumes, due primarily to the completion of three Mancos formation test wells in the San Juan and Piceance Basins, was partially offset by a 25% decrease in average price received for natural gas.

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

Depreciation, depletion and amortization increased primarily due to a higher depletion rate per Mcf on higher volumes. The increased depletion rate is primarily driven by higher capital costs per Mcfe for our Bakken oil drilling program.

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

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 (expense) benefit: The effective tax rate for the six months ended June 30, 2011 was positively impacted by a research and development credit and the benefit generated by percentage depletion had a significantly lesser impact on the effective tax rate compared to the same period in 2011.

Corporate

Results of Operations for Corporate for the Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011: Loss from continuing operations for Corporate was $13.2 million for the three months ended June 30, 2012 compared to Loss from continuing operations of $9.4 million for the three months ended June 30, 2011. The increased loss was primarily as a result of an unrealized, non-cash mark-to-market loss on certain interest rate swaps for the quarter ended June 30, 2012 of approximately $15.6 million compared to a $7.8 million unrealized, mark-to-market non-cash loss on these interest rate swaps in the prior year.

There were no allocated costs related to our Energy Marketing segment for the three months ended June 30, 2012 which could not be included in discontinued operations compared to after-tax costs of $0.5 million for the three months ended June 30, 2011.

Results of Operations for Corporate for the Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011: Loss from continuing operations for Corporate was $9.8 million for the six months ended June 30, 2012 compared to Loss from continuing operations of $9.0 million for the six months ended June 30, 2011 primarily as a result of an unrealized, non-cash mark-to-market loss on certain interest rate swaps for the quarter ended June 30, 2012 of approximately $3.5 million compared to a $2.4 million unrealized, mark-to-market non-cash loss on these interest rate swaps in the prior year.

Corporate was allocated after-tax costs of $1.6 million related to on-going costs associated with our Energy Marketing segment for the six months ended June 30, 2012 which could not be included in discontinued operations compared to after-tax costs of $1.0 million for the six months ended June 30, 2011.

Discontinued Operations

Results of Operations for Discontinued Operations for the Three and Six Months Ended June 30, 2012 Compared to Three and Six Months Ended June 30, 2011:

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds on the date of the sale were approximately $166.3 million, subject to final post-closing adjustments. The proceeds represent $108.8 million received from the buyer and $57.5 million cash retained from Enserco prior to closing.

For the three and six months ended June 30, 2012, we recorded loss from discontinued operations 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.

Pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments totaling $7.2 million. We contested this proposed adjustment and estimated the amount owed at $1.3 million, which is accrued for in the loss from discontinued operations for the three months ended June 30, 2012. If we do not reach a negotiated agreement with the buyer regarding the purchase price adjustment, resolution would occur through the dispute resolution provision of the Stock Purchase Agreement.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2011 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 2011 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

The following table summarizes our cash flows for the six months ended June 30, 2012 and 2011 (in thousands):

Cash provided by (used in):	2012	2011	Increase (Decrease)
Operating activities	$176,699	$182,017	$(5,318)
Investing activities	$(36,699)	$(225,064)	$188,365
Financing activities	$(158,658)	$98,682	$(257,340)

Year-to-Date 2012 Compared to Year-to-Date 2011

Operating Activities

Net cash provided by operating activities was $5.3 million lower for the six months ended June 30, 2012 than for the same period in 2011 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $23.4 million higher for the six months ended June 30, 2012 than for the same period the prior year.

- Net inflows from operating assets and liabilities were $24.0 million for the six months ended June 30, 2012, a decrease of $7.4 million from the same period in the prior year. In addition to other normal working capital changes, the decrease primarily related to decreased gas volumes in inventory due to warmer weather and to lower natural gas prices.

Cash contributions to the defined benefit pension plan were $25.0 million in 2012 compared to $0.6 million in 2011.

Investing Activities

Net cash used by investing activities was $188.4 million lower for the six months ended June 30, 2012 than in the same period in 2011 reflecting cash proceeds received from the sale of Enserco of $108.8 million and reduced capital expenditures of $74.6 million due to the completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and 200 MW of natural gas-fired electric generation at Black Hills Colorado IPP in 2011.

Financing Activities

Net cash used in financing activities was $257.3 million higher for the six months ended June 30, 2012 than in the same period in 2011 primarily due to applying the proceeds from the sale of Enserco to pay down short-term borrowings on the Revolving Credit Facility of approximately $110 million while in the same period in the prior year we increased borrowings to finance our construction program in Pueblo, Colorado. Cash dividends on common stock of $32.6 million were paid in 2012 compared to cash dividends paid of $29.5 million in 2011. In addition, in May 2012 Black Hills Power repaid its Pollution Control Revenue Bonds for $6.5 million.

Dividends

Dividends paid on our common stock totaled $32.6 million for the six months ended June 30, 2012, or $0.74 per share. On July 25, 2012, our Board of Directors declared a quarterly dividend of $0.37 per share payable September 1, 2012, which is equivalent to an annual dividend rate of $1.48 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 credit facility and our future business prospects.

Financing Transactions and Short-Term Liquidity

Our principal sources of short-term liquidity are our Revolving Credit Facility and cash provided by operations. In addition to availability under our Revolving Credit Facility described below, as of June 30, 2012, we had approximately $40 million of unrestricted cash. The net cash proceeds from the Enserco sale were utilized to reduce short-term debt by approximately $110 million with the remainder included in our June 30, 2012 cash balance.

Revolving Credit Facility

Our $500 million Revolving Credit Facility expiring February 1, 2017 can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50%, 1.50% and 1.50%, respectively. The facility contains a commitment fee that will be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.25%. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million.

At June 30, 2012, we had borrowings of $75 million and letters of credit outstanding of $36 million on our Revolving Credit Facility. Available capacity remaining was approximately $389 million at June 30, 2012.

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, maintenance of certain financial covenants and a recourse leverage ratio not to exceed 0.65 to 1.00. At June 30, 2012, our long-term debt ratio was 46.6%, our total debt leverage ratio (long-term debt and short-term debt) was 55.6%, and our recourse leverage ratio was approximately 56.8%.

In addition to covenant violations, an event of default under the Revolving Credit Facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $35 million or more. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans or new letters of credit, and could require both the immediate repayment of any outstanding principal and interest and the cash collateralization of outstanding letter of credit obligations.

We were in compliance with the covenants and are not in default of the terms of the Revolving Credit Facility as of June 30, 2012.

Corporate Term Loans

In June 2012, we extended our one-year $150 million unsecured, single draw term loan for one year. The cost of borrowing under the extended loan now due on June 24, 2013 is based on a spread of 1.10% over LIBOR (1.35% at June 30, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional requirement to maintain a minimum consolidated net worth. We were in compliance with these covenants as of June 30, 2012.

In December 2010, we entered into a one-year $100 million term loan with J.P. Morgan and Union Bank due in December 2011. On September 30, 2011, we extended that term loan for two years under the existing terms to September 30, 2013. The cost of borrowing under this term loan is based on a spread of 1.375% over LIBOR (1.62% at June 30, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional requirement to maintain a minimum consolidated net worth. We were in compliance with these covenants as of June 30, 2012.

Repayment of Long-term Debt

On May 15, 2012, Black Hills Power repaid its 4.8% Pollution Control Refund Revenue Bonds in full for $6.5 million principal and interest. These bonds were originally due to mature on October 1, 2014.

Dividend Restrictions

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 of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

- Our utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory authorities they can pay the utility holding company and also may have further restrictions under the Federal Power Act. As of June 30, 2012, the restricted net assets at our Electric and Gas Utilities were approximately $215.1 million.

- As required by the covenants in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted equity of at least $100.0 million. In addition, Black Hills Wyoming holds $4.8 million of restricted cash associated with the project financing requirements.

Future Financing Plans

We have substantial capital expenditures planned in 2012, which primarily include construction of additional utility generation to serve Black Hills Power and Cheyenne Light customers, wind generation to meet renewable standards in Colorado, environmental upgrades and replacements to existing generation to meet governmental pollution control mandates and potential capital deployment in oil and gas drilling to prove-up reserves. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility, term loans and long-term financings and other debt or equity issuances.

We have debt due of $225 million and $250 million in 2013 and 2014, respectively. In addition, we have term loans of $250 million expiring in 2013. With these upcoming financing requirements, we continue to evaluate various financing options that include senior unsecured notes, first mortgage bonds, term loans and project financing opportunities and issuance. We anticipate executing financing transactions ahead of these maturities by late 2012 or early 2013 depending on market conditions.

We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, due to capital projects, we may exceed this level on a temporary basis. We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements.

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 and Comprehensive Income. For the three and six months ended June 30, 2012, respectively, we recorded $15.6 million and $3.5 million pre-tax unrealized mark-to-market non-cash losses on the swaps. The mark-to-market value on these swaps was a liability of $93.3 million at June 30, 2012. 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 over the term of the swaps would have a pre-tax impact of approximately $0.4 million. These swaps are for terms of 6.5 and 16.5 years and have amended early termination dates ranging from December 15, 2012 to December 16, 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, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Black Hills Power and Cheyenne Light customers, and because of our upcoming holding company debt maturities, which are $225 million and $250 million in 2013 and 2014, respectively. 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 termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 4.5 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 $25.7 million at June 30, 2012.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2011 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms including collateral requirements. As of June 30, 2012, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

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

* In July 2012, S&P published its updated credit review, leaving unchanged our senior unsecured credit rating of BBB- and upgraded our risk profile to excellent from strong.

In addition, as of June 30, 2012, Black Hills Power's first mortgage bonds were rated as follows:

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

Capital Requirements

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

	Expenditures for the Six Months Ended June 30, 2012	Total 2012 Planned Expenditures	Total 2013 Planned Expenditures	Total 2014 Planned Expenditures
Utilities:				
Electric Utilities (1)	$83,077	$179,100	$279,500	$187,000
Gas Utilities	17,880	57,700	54,700	55,800
Non-regulated Energy:				
Power Generation	5,704	7,300	4,900	6,700
Coal Mining	8,227	14,600	7,200	10,800
Oil and Gas (2)	43,031	86,300	114,600	113,100
Corporate	5,562	10,300	11,800	4,700
	$163,481	$355,300	$472,700	$378,100

(1) Planned expenditures in 2012 and 2013 of $22 million and $27 million, respectively, for the proposed 88 MW of gas-fired generation at Colorado Electric have been removed from the forecasted expenditures reported in our 2011 Annual Report on Form 10-K as a result of the denial of our request for a CPCN.

(2) Capital expenditures at our Oil and Gas Segment are driven by economics and may vary depending on the pricing environment for crude oil and natural gas. Forecasted expenditures for 2012, 2013 and 2014 shown above for the Oil and Gas segment have been decreased $25.9 million, $8.9 million and $13 million, respectively, from the amounts reported in our 2011 Annual Report on Form 10-K due to delaying our gas drilling program as a result of lower natural gas prices.

We continually evaluate all of our forecasted capital expenditures, and if determined prudent, we may defer some of these expenditures for a period of time. Future projects are dependent upon the availability of attractive economic opportunities, and as a result, actual expenditures may vary significantly from forecasted estimates.

Contractual Obligations

There have been no significant changes to contractual obligations or any off-balance sheet arrangements from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Guarantees

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 2011 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2011 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A of our 2011 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, and the following:

- The ability to successfully resolve the purchase price adjustments in question from the sale of Enserco.

- We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and therefore may not have sufficient cash available for our peak winter needs and other working capital requirements, and our forecasted capital expenditure requirements.

- Counterparties may default on their obligations to supply commodities, return collateral to us, or otherwise meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.

- We expect to fund a portion of our forecasted capital requirements through a combination of long-term debt and equity issuances. However capital market conditions and market uncertainties related to interest rates may affect our ability to raise capital on favorable terms.

- We expect to make approximately $355.3 million, $472.7 million and $378.1 million of capital expenditures in 2012, 2013 and 2014, respectively. Some important factors that could cause actual expenditures to differ materially from those anticipated include:

- The timing of planned generation, transmission or distribution projects for our Utilities Group is influenced by state and federal regulatory authorities and third parties. The occurrence of events that impact (favorably or unfavorably) our ability to make planned or unplanned capital expenditures have caused and could cause our forecasted capital expenditures to change.

- Forecasted capital expenditures associated with our Oil and Gas segment are driven, in part, by current commodity prices, our ability to obtain permits, availability and costs of drilling and service equipment and crews, and our ability to negotiate agreements with property owners for land use. Changes in crude oil and natural gas prices have caused and may cause us to change our planned capital expenditures related to our oil and gas operations. An inability to obtain permits, equipment or land use rights could delay drilling efforts.

- Our ability to complete our planned capital expenditures associated with our Oil and Gas segment may be impacted by our ability to obtain necessary drilling permits, and other necessary contract services and equipment such as drilling rigs, hydraulic fracturing services and other support services. Our plans may also be negatively impacted by weather conditions and existing or proposed regulations, including possible hydraulic fracturing regulations.

- Our ability to complete the planning, permitting, construction, start-up and operation of power generation facilities in a cost-efficient and timely manner.

- We expect contributions to our defined benefit pension plans to be approximately $0.0 million and $4.5 million for the remainder of 2012 and for 2013, respectively. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

- The actual value of the plans' invested assets.

- The discount rate used in determining the funding requirement.

- We expect the goodwill related to our utility assets to fairly reflect the long-term value of stable, long-lived utility assets. Some important factors that could cause us to revisit the fair value of this goodwill include:

- A significant and sustained deterioration of the market value of our common stock.

- Negative regulatory orders, condemnation proceedings or other events that materially impact our Utilities Groups' ability to generate sufficient stable cash flow over an extended period of time.

- The effects of changes in the market including significant changes in the risk-adjusted discount rate or growth rates.

- The timing, volatility, and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets, including the possibility that we may be required to take future impairment charges under the SEC's full cost ceiling test for natural gas and crude oil reserves.

- Federal and state laws concerning climate change and air emissions, including emission reduction mandates, carbon emissions and renewable energy portfolio standards, may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain or which could mandate or require closure of one or more of our generating units.

- We have debt due of $225 million and $250 million in 2013 and 2014, respectively. In addition, we have term loans of $250 million expiring in 2013. We are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and debt and equity issuance in the capital markets. Some important factors that could impact our ability to complete one or more of these financings include:

- Our ability to access the bank loan and debt and equity capital markets depends on market conditions beyond our control. If the capital markets deteriorate, we may not be able to refinance our short-term debt and fund our capital projects on reasonable terms, if at all.

- Our ability to raise capital in the debt capital markets depends upon our financial condition and credit ratings, among other things. If our financial condition deteriorates unexpectedly, or our credit ratings are lowered, we may not be able to refinance some short-term debt and fund our power generation projects on reasonable terms, if at all.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to the effect of volatile natural gas prices. We produce, purchase and distribute power in four states and purchase and distribute natural gas in five states, and we utilize natural gas as fuel at our Electric Utilities. All of our gas utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas and services through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to true-up billed amounts to match the actual natural gas cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. We have ECA mechanisms in South Dakota, Colorado, Wyoming and Montana for our electric utilities that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs and transmission costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer.

As allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to the volatility of natural gas prices. These transactions are considered derivatives and are marked-to-market. Gains or losses, as well as option premiums on these transactions, are recorded in Regulatory assets or Regulatory liabilities. Once settled, the gains and losses are passed on to our customers through the PGA.

The fair value of our Utilities Group's derivative contracts is summarized below (in thousands):

	June 30, 2012	December 31, 2011	June 30, 2011
Net derivative (liabilities) assets	$(12,453)	$(16,676)	$(3,441)
Cash collateral	15,925	19,416	6,254
	$3,472	$2,740	$2,813

Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2012, 2013 and 2014 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at June 30, 2012 were as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2012					
Swaps - MMBtu			1,334,000	1,196,000	2,530,000
Weighted Average Price per MMBtu			$3.99	$3.74	$3.87
2013					
Swaps - MMBtu	1,220,000	1,233,000	1,246,000	1,386,500	5,085,500
Weighted Average Price per MMBtu	$4.01	$3.55	$3.33	$3.47	$3.58
2014					
Swaps - MMBtu	950,000	455,000			1,405,000

Weighted Average Price per MMBtu	$3.71	$3.45		$3.63

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2012					
Swaps - Bbls			57,000	57,000	114,000
Weighted Average Price per Bbl			$88.37	$96.56	$92.46
Puts - Bbls			21,000	21,000	42,000
Weighted Average Price per Bbl			$76.43	$76.43	$76.43
Calls - Bbls			21,000	21,000	42,000
Weighted Average Price per Bbl			$95.00	$95.00	$95.00
2013					
Swaps - Bbls	45,000	36,000	36,000	15,000	132,000
Weighted Average Price per Bbl	$98.93	$102.64	$100.49	$101.75	$100.69
Puts - Bbls	30,000	36,000	39,000	36,000	141,000
Weighted Average Price per Bbl	$76.75	$78.96	$79.81	$80.63	$79.15
Calls - Bbls	30,000	36,000	39,000	36,000	141,000
Weighted Average Price per Bbl	$96.50	$97.17	$97.08	$97.25	$97.02
2014					
Swaps - Bbls	45,000	15,000			60,000
Weighted Average Price per Bbl	$94.38	$82.75			$91.48

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. As of June 30, 2012, we had $150 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 4.5 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the Condensed Consolidated Balance Sheets.

We also have interest rate swaps with a notional amount of $250 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges and the mark-to-market value was recorded in Accumulated other comprehensive income (loss) on the Condensed Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and, as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the Condensed Consolidated Statements of Income and Comprehensive Income. For the three months and six months ended June 30, 2012, we recorded pre-tax unrealized mark-to-market losses of $15.6 million and $3.5 million, respectively. For the three months and six months ended June 30, 2011, we recorded pre-tax unrealized mark-to-market losses of $7.8 million and $2.4 million, respectively. These swaps are 7 and 17 year swaps which have amended early termination dates ranging from December 15, 2012 to December 16, 2013.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. 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 stated termination dates.

Further details of the swap agreements are set forth in Note 13 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

As of June 30, 2012, December 31, 2011 and June 30, 2011, our interest rate swaps and related balances were as follows (dollars in thousands):

	June 30, 2012		December 31, 2011		June 30, 2011	
	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	4.5	1.5	5.0	2.0	5.5	0.5
Derivative liabilities, current	$6,766	$78,001	$6,513	$75,295	$6,900	$56,342
Derivative liabilities, non-current	$18,976	$15,336	$20,363	$20,696	$15,788	$—
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(25,742)	$—	$(26,876)	$—	$(22,688)	$—
Pre-tax (loss) gain included in Condensed Consolidated Statements of Income and Comprehensive Income	$—	$(3,507)	$—	$(42,010)	$—	$(2,362)
Cash collateral receivable (payable) included in accounts receivable	$—	$6,160	$—	$—	$—	$—

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* Maximum terms in years for our de-designed 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 million terminate in 6.5 years and de-designated swaps totaling $150 million terminate in 16.5 years.

Based on June 30, 2012 market interest rates and balances for our designated interest rate swaps, a loss of approximately $6.8 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will change during the next 12 months as market interest rates change.

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ITEM 4. CONTROLS AND PROCEDURES

This section should be read in conjunction with Item 9A, "Controls and Procedures" included in our Annual Report on Form 10-K for the year ended December 31, 2011.

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, 2012 and concluded that, because of the material weakness in our internal control over financial reporting related to accounting for income taxes as previously disclosed in Item 9A, “Controls and Procedures” in our Annual Report on Form 10-K for the year ended December 31, 2011, our disclosure controls and procedures were not effective as of June 30, 2012. Additional review, evaluation and oversight have been undertaken to ensure our unaudited Condensed Consolidated Financial Statements were prepared in accordance with generally accepted accounting principles and as a result, our management, including our Chief Executive Officer and Chief Financial Officer, have concluded that the Condensed Consolidated Financial Statements in this Form 10-Q fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in conformity with accounting principles generally accepted in the United States.

As discussed in our 2011 Annual Report on Form 10-K, management concluded that while we had appropriately designed control procedures for income tax accounting and disclosures, the existence of non-routine transactions, insufficient tax resources, and ineffective communications between the tax department and Controller organization caused us to poorly execute the controls for evaluating and recording income taxes. Management has developed and is implementing a remediation plan to address this material weakness in internal controls surrounding accounting for income taxes. Key aspects of the remediation plan include enhancing resources and skill sets and implementing formal periodic meetings among the Chief Financial Officer, Controller and the tax department.

While we concluded our internal controls surrounding income taxes were not effective as of June 30, 2012, we are remediating the material weakness and will continue to execute our remediation plan and track our performance against the plan.

During the quarter ended June 30, 2012, there have been no other 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 2011 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2011.

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, 2012 - April 30, 2012	—	$—	—	—
May 1, 2012 - May 31, 2012	1,673	$32.47	—	—
June 1, 2012 - June 30, 2012	—	$—	—	—
Total	1,673	$32.47	—	—

(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 10 *	First Amendment to the Credit Agreement dated June 22, 2012 among Black Hills Corporation, as Borrower, the Bank of Nova Scotia, in its capacity as agent for the Banks and a Bank, and each of the other Banks (filed as Exhibit 10 to the Registrant's Form 8-K filed on June 26, 2012).
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.

BLACK HILLS CORPORATION

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 7, 2012

EXHIBIT INDEX

Exhibit Number	Description
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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.