BLACK HILLS CORP /SD/
Form 10-Q
November 05, 2013

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2013

OR

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

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701
Registrant's telephone number (605) 721-1700
Former name, former address, and former fiscal year if changed since last report
NONE

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

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

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

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

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

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

| Class | Outstanding at October 31, 2013 | |
|---|---|---|
| Common stock, $1.00 par value | 44,485,101 | shares |

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## GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

| | |
|---|---|
| AFUDC | Allowance for Funds Used During Construction |
| AOCI | Accumulated Other Comprehensive Income (Loss) |
| ASU | Accounting Standards Update |
| Basin Electric | Basin Electric Power Cooperative |
| Bbl | Barrel |
| BHC | Black Hills Corporation; the Company |
| BHEP | Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, and Black Hills Gas Resources, Inc. and Black Hills Plateau Production, LLC, direct wholly-owned subsidiaries of Black Hills Exploration and Production, Inc. |
| Black Hills Electric Generation | Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings |
| Black Hills Energy | The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries |
| Black Hills Non-regulated Holdings | Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation |
| Black Hills Power | Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation |
| Black Hills Utility Holdings | Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation |
| Black Hills Wyoming | Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation |
| Cheyenne Light | Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation |
| Cheyenne Prairie | Cheyenne Prairie Generating Station, a 132 megawatt generating facility, currently being constructed in Cheyenne, Wyo. by Cheyenne Light and Black Hills Power. |
| Colorado Electric | Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings |
| Colorado IPP | Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation |
| Cooling degree day | A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average. |
| Conflict Minerals | As defined by Dodd-Frank, conflict minerals are cassiterite, columbite-tantalite, gold and wolframite that are mined in the Democratic Republic of the Congo or surrounding countries |
| CPCN | Certificate of Public Convenience and Necessity |
| CPUC | Colorado Public Utilities Commission |

| | |
|---|---|
| CTII | The 40 megawatt Gillette CT, a simple-cycle, gas-fired combustion turbine owned by Black Hills Wyoming |
| CVA | Credit Valuation Adjustment, an adjustment to the measurement of derivatives to reflect the default risk of the counterparty. |
| De-designated interest rate swaps | The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but were subsequently de-designated |
| Dodd-Frank | Dodd-Frank Wall Street Reform and Consumer Protection Act |
| Dth | Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu) |
| Enserco | Enserco Energy Inc., representing our Energy Marketing segment, sold Feb. 29, 2012 |
| FASB | Financial Accounting Standards Board |
| FERC | United States Federal Energy Regulatory Commission |
| Fitch | Fitch Ratings |
| GAAP | Accounting principles generally accepted in the United States of America |
| Heating Degree Day | A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average. |
| Iowa Gas | Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings |
| IPP | Independent power producer |
| IRS | United States Internal Revenue Service |
| IUB | Iowa Utilities Board |
| Kansas Gas | Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings |
| LIBOR | London Interbank Offered Rate |
| LOE | Lease Operating Expense |
| Mcf | Thousand cubic feet of natural gas |
| Mcfe | Thousand cubic feet equivalent. Natural gas liquid is converted by dividing gallons by 7. Crude oil is converted by multiplying barrels by 6. |
| MMBtu | Million British thermal units |
| Moody’s | Moody’s Investors Service, Inc. |
| MWh | Megawatt-hour |

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| | |
|---|---|
| NGL | Natural Gas Liquids. One gallon equals 1/7 Mcfe |
| NOL | Net Operating Loss |
| OTC | Over-the-counter |
| PPA | Power Purchase Agreement |
| PSCo | Public Service Company of Colorado |
| Revolving Credit Facility | Our $500 million credit facility which matures in 2017 |
| SDPUC | South Dakota Public Utilities Commission |
| SEC | U. S. Securities and Exchange Commission |
| S&P | Standard and Poor’s, a division of The McGraw-Hill Companies, Inc. |
| WPSC | Wyoming Public Service Commission |

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

| (unaudited) | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| | (in thousands, except per share and per share amounts) | | | |
| Revenue | $259,907 | $246,808 | $920,404 | $855,022 |
| Operating expenses: | | | | |
| Utilities - | | | | |
| Fuel, purchased power and cost of gas sold | 71,503 | 62,582 | 338,848 | 283,217 |
| Operations and maintenance | 66,061 | 59,398 | 196,728 | 183,721 |
| Non-regulated energy operations and maintenance | 20,484 | 22,466 | 62,703 | 65,774 |
| Gain on sale of operating assets | — | (27,285) | — | (27,285) |
| Depreciation, depletion and amortization | 36,135 | 41,408 | 106,068 | 121,398 |
| Taxes - property, production and severance | 10,068 | 10,213 | 30,517 | 31,201 |
| Impairment of long-lived assets | — | — | — | 26,868 |
| Other operating expenses | 90 | 216 | 1,091 | 1,679 |
| Total operating expenses | 204,341 | 168,998 | 735,955 | 686,573 |
| Operating income | 55,566 | 77,810 | 184,449 | 168,449 |
| Other income (expense): | | | | |
| Interest charges - | | | | |
| Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps) | (23,840) | (27,475) | (70,881) | (85,151) |
| Allowance for funds used during construction - borrowed | 347 | 1,127 | 831 | 2,608 |
| Capitalized interest | 273 | 175 | 811 | 467 |
| Unrealized gain (loss) on interest rate swaps, net | 3,144 | 605 | 29,393 | (2,902) |
| Interest income | 565 | 364 | 1,325 | 1,428 |
| Allowance for funds used during construction - equity | 85 | 196 | 327 | 668 |
| Other income (expense), net | 318 | (287) | 1,197 | 2,073 |
| Total other income (expense), net | (19,108) | (25,295) | (36,997) | (80,809) |
| Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes | 36,458 | 52,515 | 147,452 | 87,640 |
| Equity in earnings (loss) of unconsolidated subsidiaries | — | 22 | (86) | (12) |
| Income tax benefit (expense) | (13,334) | (17,914) | (50,527) | (30,057) |
| Income (loss) from continuing operations | 23,124 | 34,623 | 96,839 | 57,571 |
| Income (loss) from discontinued operations, net of tax | — | (166) | — | (6,810) |
| Net income (loss) available for common stock | $23,124 | $34,457 | $96,839 | $50,761 |
| Earnings (loss) per share, Basic - | | | | |
| Income (loss) from continuing operations, per share | $0.52 | $0.79 | $2.19 | $1.31 |

| | | | | |
|---|---|---|---|---|
| Income (loss) from discontinued operations, per share | — | — | — | (0.16 ) |
| Total income (loss) per share, Basic | $0.52 | $0.79 | $2.19 | $1.15 |
| Earnings (loss) per share, Diluted - | | | | |
| Income (loss) from continuing operations, per share | $0.52 | $0.78 | $2.18 | $1.31 |
| Income (loss) from discontinued operations, per share | — | — | — | (0.16 ) |
| Total income (loss) per share, Diluted | $0.52 | $0.78 | $2.18 | $1.15 |
| Weighted average common shares outstanding: | | | | |
| Basic | 44,201 | 43,847 | 44,143 | 43,792 |
| Diluted | 44,457 | 44,108 | 44,395 | 44,026 |
| | | | | |
| Dividends paid per share of common stock | $0.380 | $0.370 | $1.140 | $1.110 |

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

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

| (unaudited) | Three Months Ended Sept. 30, 2013 | 2012 | Nine Months Ended Sept. 30, 2013 | 2012 |
|---|---|---|---|---|
| | (in thousands) | | | |
| Net income (loss) available for common stock | $23,124 | $34,457 | $96,839 | $50,761 |
| Other comprehensive income (loss), net of tax: | | | | |
| Fair value adjustment on derivatives designated as cash flow hedges (net of tax (expense) benefit of $964 and $1,204 for the three months ended 2013 and 2012 and $(93) and $1,092 for the nine months ended 2013 and 2012, respectively) | (2,083) | (3,591) | 134 | (3,004) |
| Reclassification adjustments related to defined benefit plan (net of tax of $(220) for the three months ended 2013 and $(663) for the nine months ended 2013) | 417 | — | 1,238 | — |
| Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(586) and $13 for the three months ended 2013 and 2012 and $(1,469) and $890 for the nine months ended 2013 and 2012, respectively) | 1,426 | 28 | 3,095 | (1,333) |
| Other comprehensive income (loss), net of tax | (240) | (3,563) | 4,467 | (4,337) |
| Comprehensive income (loss) available for common stock | $22,884 | $30,894 | $101,306 | $46,424 |

See Note 7 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

| | As of Sept. 30, 2013 | Dec. 31, 2012 | Sept. 30, 2012 |
|---|---|---|---|
| | (in thousands) | | |
| ASSETS | | | |
| Current assets: | | | |
| Cash and cash equivalents | $13,637 | $15,462 | $247,192 |
| Restricted cash and equivalents | 6,782 | 7,916 | 7,302 |
| Accounts receivable, net | 114,137 | 163,698 | 104,482 |
| Materials, supplies and fuel | 95,230 | 77,643 | 80,900 |
| Derivative assets, current | 126 | 3,236 | 16,063 |
| Income tax receivable, net | 4,539 | — | 11,869 |
| Deferred income tax assets, net, current | 37,163 | 77,231 | 33,681 |
| Regulatory assets, current | 30,208 | 31,125 | 24,606 |
| Other current assets | 27,075 | 28,795 | 44,823 |
| Total current assets | 328,897 | 405,106 | 570,918 |
| | | | |
| Investments | 16,612 | 16,402 | 16,273 |
| | | | |
| Property, plant and equipment | 4,152,097 | 3,930,772 | 3,950,222 |
| Less: accumulated depreciation and depletion | (1,258,450) | (1,188,023) | (1,253,808) |
| Total property, plant and equipment, net | 2,893,647 | 2,742,749 | 2,696,414 |
| | | | |
| Other assets: | | | |
| Goodwill | 353,396 | 353,396 | 353,396 |
| Intangible assets, net | 3,453 | 3,620 | 3,675 |
| Derivative assets, non-current | — | 510 | 1,167 |
| Regulatory assets, non-current | 183,119 | 188,268 | 191,935 |
| Other assets, non-current | 22,116 | 19,420 | 19,850 |
| Total other assets, non-current | 562,084 | 565,214 | 570,023 |
| | | | |
| TOTAL ASSETS | $3,801,240 | $3,729,471 | $3,853,628 |

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

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

| | As of | | |
|---|---|---|---|
| | Sept. 30, 2013 | Dec. 31, 2012 | Sept. 30, 2012 |
| | (in thousands, except share amounts) | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | |
| Current liabilities: | | | |
| Accounts payable | $77,077 | $84,422 | $69,138 |
| Accrued liabilities | 152,911 | 154,389 | 179,284 |
| Derivative liabilities, current | 65,944 | 96,541 | 86,509 |
| Accrued income tax, net | — | 4,936 | — |
| Regulatory liabilities, current | 14,707 | 13,628 | 10,705 |
| Notes payable | 138,300 | 277,000 | 225,000 |
| Current maturities of long-term debt | 255,694 | 103,973 | 328,310 |
| Total current liabilities | 704,633 | 734,889 | 898,946 |
| | | | |
| Long-term debt, net of current maturities | 955,979 | 938,877 | 942,950 |
| | | | |
| Deferred credits and other liabilities: | | | |
| Deferred income tax liabilities, net, non-current | 403,772 | 385,908 | 338,194 |
| Derivative liabilities, non-current | 11,388 | 16,941 | 41,410 |
| Regulatory liabilities, non-current | 131,730 | 127,656 | 120,491 |
| Benefit plan liabilities | 169,448 | 167,397 | 167,690 |
| Other deferred credits and other liabilities | 133,341 | 125,294 | 129,630 |
| Total deferred credits and other liabilities | 849,679 | 823,196 | 797,415 |
| | | | |
| Commitments and contingencies (See Notes 5, 8, 10 and 13) | | | |
| | | | |
| Stockholders' equity: | | | |
| Common stock equity — | | | |
| Common stock $1 par value; 100,000,000 shares authorized; issued 44,532,245; 44,278,189; and 44,250,588 shares, respectively | 44,532 | 44,278 | 44,251 |
| Additional paid-in capital | 740,209 | 733,095 | 731,176 |
| Retained earnings | 539,030 | 492,869 | 478,459 |
| Treasury stock, at cost – 47,127; 71,782; and 75,420 shares, respectively | (1,801) | (2,245) | (2,354) |
| Accumulated other comprehensive income (loss) | (31,021) | (35,488) | (37,215) |
| Total stockholders' equity | 1,290,949 | 1,232,509 | 1,214,317 |
| | | | |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | $3,801,240 | $3,729,471 | $3,853,628 |

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) | Nine Months Ended Sept. 30, | |
|---|---|---|
| | 2013 | 2012 |
| Operating activities: | (in thousands) | |
| Net income (loss) available to common stock | $96,839 | $50,761 |
| (Income) loss from discontinued operations, net of tax | — | 6,810 |
| Income (loss) from continuing operations | 96,839 | 57,571 |
| Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 106,068 | 121,398 |
| Deferred financing cost amortization | 3,209 | 5,301 |
| Impairment of long-lived assets | — | 26,868 |
| Derivative fair value adjustments | 275 | (3,522) |
| Gain on sale of operating assets | — | (27,285) |
| Stock compensation | 9,100 | 5,974 |
| Unrealized (gain) loss on interest rate swaps, net | (29,393) | 2,902 |
| Deferred income taxes | 54,865 | 28,718 |
| Employee benefit plans | 16,644 | 15,737 |
| Other adjustments, net | 9,434 | 2,837 |
| Changes in certain operating assets and liabilities: | | |
| Materials, supplies and fuel | (12,522) | 3,085 |
| Accounts receivable, unbilled revenues and other operating assets | 28,762 | 56,301 |
| Accounts payable and other current liabilities | (23,774) | (22,041) |
| Contributions to defined benefit pension plans | (12,500) | (25,000) |
| Other operating activities, net | 4,759 | (361) |
| Net cash provided by operating activities of continuing operations | 251,766 | 248,483 |
| Net cash provided by (used in) operating activities of discontinued operations | — | 21,184 |
| Net cash provided by operating activities | 251,766 | 269,667 |
| | | |
| Investing activities: | | |
| Property, plant and equipment additions | (239,485) | (261,414) |
| Proceeds from sale of assets | — | 268,482 |
| Investment in notes receivable | — | (21,832) |
| Other investing activities | 2,846 | 5,057 |
| Net cash provided by (used in) investing activities of continuing operations | (236,639) | (9,707) |
| Proceeds from sale of discontinued business operations | — | 108,837 |
| Net cash provided by (used in) investing activities of discontinued operations | — | (824) |
| Net cash provided by (used in) investing activities | (236,639) | 98,306 |
| | | |
| Financing activities: | | |
| Dividends paid on common stock | (50,678) | (48,904) |
| Common stock issued | 3,606 | 3,835 |
| Short-term borrowings - issuances | 269,600 | 62,453 |
| Short-term borrowings - repayments | (408,300) | (182,453) |
| Long-term debt - issuances | 275,000 | — |
| Long-term debt - repayments | (106,180) | (11,647) |
| Other financing activities | — | (2,833) |

| | | |
|---|---|---|
| Net cash provided by (used in) financing activities of continuing operations | (16,952) | (179,549) |
| Net cash provided by (used in) financing activities of discontinued operations | — | — |
| Net cash provided by (used in) financing activities | (16,952) | (179,549) |
| Net change in cash and cash equivalents | (1,825) | 188,424 |
| Cash and cash equivalents, beginning of period | 15,462 | 58,768 * |
| Cash and cash equivalents, end of period | $13,637 | $247,192 |

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

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2012 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company," "us," "we," or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2012 Annual Report on Form 10-K filed with the SEC.

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Coal Mining and Oil and Gas. Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the Sept. 30, 2013, Dec. 31, 2012, and Sept. 30, 2012 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended Sept. 30, 2013 and Sept. 30, 2012, and our financial condition as of Sept. 30, 2013, Dec. 31, 2012, and Sept. 30, 2012, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

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

Recently Adopted Accounting Standards

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

In February 2013, the FASB issued ASU 2013-02 which requires new disclosures for items reclassified out of AOCI. ASU 2013-02 requires disclosure of (1) changes in components of other comprehensive income, (2) items reclassified out of AOCI and into net income in their entirety, the effect of the reclassification on each affected net income line item and (3) cross references to other disclosures that provide additional detail for components of other comprehensive income that are not reclassified in their entirety to net income. Disclosures are required either on the face of the statements of income or as a separate disclosure in the notes to the financial statements. The new disclosure requirements are effective for interim and annual periods beginning after Dec. 15, 2012. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows. See additional disclosures in Note 7.

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

In December 2011, the FASB issued revised accounting guidance to amend disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures. The revised disclosure guidance affects all companies that have financial instruments and derivative instruments that are either offset in the balance sheet (i.e., presented on a net basis) or subject to an enforceable master netting and/or similar arrangement. In addition, the revised guidance requires that certain enhanced quantitative and qualitative disclosures are made with respect to a company’s netting arrangements and/or rights of offset associated with its financial instruments and/or derivative instruments. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning Jan. 1, 2013. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows. See additional disclosures in Note 11.

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

In July 2013, the FASB issued an amendment to accounting for derivatives and hedges to permit the Fed Funds Effective Swap Rate to be used as a U.S. benchmark interest rate for hedge accounting purposes effective for new or re-designated hedging relationships entered into on or after July 17, 2013. The amendment also removed the restriction on using different benchmark rates for similar hedges. The initial adoption had no impact on our consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements and Legislation

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, ASU 2013-11

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

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

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

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

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

Tangible Personal Property, IRS T.D. 9636

In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with the acquisition, production and improvement of tangible property. We continue to evaluate what impact the adoption of the regulations will have on our consolidated financial statements. As of this date, we do not expect the adoption of the regulations to have a material impact on our consolidated financial statements.

(2) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

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

| | Nine Months Ended | |
|---|---|---|
| | Sept. 30, 2013 | Sept. 30, 2012 |
| Non-cash investing and financing activities from continuing operations— | | |
| Property, plant and equipment acquired with accrued liabilities | $47,214 | $39,303 |
| Increase (decrease) in capitalized assets associated with asset retirement obligations | $— | $3,806 |
| | | |
| Cash (paid) refunded during the period for continuing operations— | | |
| Interest (net of amounts capitalized) | $(57,175) | $(69,901) |
| Income taxes, net | $(4,924) | $425 |

(3) MATERIALS, SUPPLIES AND FUEL

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

| | Sept. 30, 2013 | Dec. 31, 2012 | Sept. 30, 2012 |
|---|---|---|---|
| Materials and supplies | $50,564 | $43,397 | $43,847 |
| Fuel - Electric Utilities | 6,384 | 8,589 | 8,289 |
| Natural gas in storage held for distribution | 38,282 | 25,657 | 28,764 |
| Total materials, supplies and fuel | $95,230 | $77,643 | $80,900 |

(4) ACCOUNTS RECEIVABLE

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

| Sept. 30, 2013 | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $49,254 | $20,153 | $(648) | $68,759 |
| Gas Utilities | 20,693 | 11,877 | (542) | 32,028 |
| Power Generation | 3 | — | — | 3 |
| Coal Mining | 2,677 | — | — | 2,677 |
| Oil and Gas | 8,463 | — | (19) | 8,444 |
| Corporate | 2,226 | — | — | 2,226 |
| Total | $83,316 | $32,030 | $(1,209) | $114,137 |

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

| Sept. 30, 2012 | Accounts Receivable, Trade | Unbilled Revenue | Less Allowance for Doubtful Accounts | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $46,802 | $18,441 | $(603) | $64,640 |
| Gas Utilities | 18,198 | 9,480 | (204) | 27,474 |
| Power Generation | 4 | — | — | 4 |
| Coal Mining | 1,540 | — | — | 1,540 |
| Oil and Gas | 10,272 | — | (105) | 10,167 |
| Corporate | 657 | — | — | 657 |
| Total | $77,473 | $27,921 | $(912) | $104,482 |

(5) NOTES PAYABLE AND LONG-TERM DEBT

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

| | Sept. 30, 2013 | | Dec. 31, 2012 | | Sept. 30, 2012 | |
|---|---|---|---|---|---|---|
| | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit |
| Revolving Credit Facility | $138,300 | $53,137 | $127,000 | $36,300 | $75,000 | $36,300 |
| Term Loan due June 2013 | — | — | 150,000 | — | 150,000 | — |
| Total | $138,300 | $53,137 | $277,000 | $36,300 | $225,000 | $36,300 |

Replacement of Notes Payable and Long-Term Term Loan

On June 21, 2013, we entered into a new $275 million term loan expiring on June 19, 2015. The proceeds from this new term loan repaid the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on Sept. 30, 2013, and $25 million in short-term borrowing under our Revolving Credit Facility. At Sept. 30, 2013, the cost of borrowing under this new term loan was 1.3125 percent (LIBOR plus a margin of 1.125 percent). The covenants of the new term loan are substantially the same as the Revolving Credit Facility.

Debt Covenants

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

| | As of Sept. 30, 2013 | Covenant Requirement |
|---|---|---|
| Recourse Leverage Ratio | 52.0 % | Less than 65.0 % |

As of Sept. 30, 2013, we were in compliance with this covenant.

(6) EARNINGS PER SHARE

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Income (loss) from continuing operations | $23,124 | $34,623 | $96,839 | $57,571 |
| Weighted average shares - basic | 44,201 | 43,847 | 44,143 | 43,792 |
| Dilutive effect of: | | | | |
| Restricted stock | 131 | 175 | 137 | 159 |
| Stock options | 13 | 12 | 13 | 14 |
| Other dilutive effects | 112 | 74 | 102 | 61 |
| Weighted average shares - diluted | 44,457 | 44,108 | 44,395 | 44,026 |

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Stock options | — | 77 | 9 | 101 |
| Restricted stock | — | 61 | — | 53 |
| Other stock | — | — | — | 19 |
| Anti-dilutive shares | — | 138 | 9 | 173 |

(7) OTHER COMPREHENSIVE INCOME (LOSS)

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

| | Location on the Condensed Consolidated Statements of Income (Loss) | Amount Reclassified from AOCI Three Months Ended Sept. 30, 2013 | Three Months Ended Sept. 30, 2012 | Nine Months Ended Sept. 30, 2013 | Nine Months Ended Sept. 30, 2012 |
|---|---|---|---|---|---|
| Gains (losses) on cash flow hedges: | | | | | |
| Interest rate swaps | Interest expense | $1,844 | $1,853 | $5,460 | $5,518 |
| Commodity contracts | Revenue | 168 | (1,838) | (896) | (7,741) |
| | | 2,012 | 15 | 4,564 | (2,223) |
| Income tax | Income tax benefit (expense) | (586) | 13 | (1,469) | 890 |
| Reclassification adjustments related to cash flow hedges, net of tax | | $1,426 | $28 | $3,095 | $(1,333) |
| | | | | | |
| Amortization of defined benefit plans: | | | | | |
| Prior service cost | Utilities - Operations and maintenance | $(31) | $— | $(93) | $— |
| | Non-regulated energy operations and maintenance | (32) | — | (96) | — |
| Actuarial gain (loss) | Utilities - Operations and maintenance | 425 | — | 1,267 | — |
| | Non-regulated energy operations and maintenance | 275 | — | 823 | — |
| | | 637 | — | 1,901 | — |
| Income tax | Income tax benefit (expense) | (220) | — | (663) | — |
| Reclassification adjustments related to defined benefit plans, net of tax | | $417 | $— | $1,238 | $— |

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

| | Derivatives Designated as Cash Flow Hedges | Employee Benefit Plans | Total |
|---|---|---|---|
| Balance as of Dec. 31, 2011 | $(13,802) | $(19,076) | $(32,878) |
| Other comprehensive income (loss), net of tax | (166) | — | (166) |
| Balance as of March 31, 2012 | (13,968) | (19,076) | (33,044) |
| Other comprehensive income (loss), net of tax | (608) | — | (608) |
| Balance as of June 30, 2012 | (14,576) | (19,076) | (33,652) |
| Other comprehensive income (loss), net of tax | (3,563) | — | (3,563) |
| Ending Balance Sept. 30, 2012 | $(18,139) | $(19,076) | $(37,215) |
| | | | |
| Balance as of Dec. 31, 2012 | $(15,713) | $(19,775) | $(35,488) |
| Other comprehensive income (loss), net of tax | (1,193) | 457 | (736) |
| Balance as of March 31, 2013 | (16,906) | (19,318) | (36,224) |
| Other comprehensive income (loss), net of tax | 5,079 | 364 | 5,443 |
| Balance as of June 30, 2013 | (11,827) | (18,954) | (30,781) |
| Other comprehensive income (loss), net of tax | (657) | 417 | (240) |
| Ending Balance Sept. 30, 2013 | $(12,484) | $(18,537) | $(31,021) |

## (8) EMPLOYEE BENEFIT PLANS

### Defined Benefit Pension Plans

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Service cost | $1,608 | $1,431 | $4,824 | $4,291 |
| Interest cost | 3,825 | 3,688 | 11,475 | 11,062 |
| Expected return on plan assets | (4,654) | (4,084) | (13,962) | (12,252) |
| Prior service cost | 16 | 22 | 48 | 66 |
| Net loss (gain) | 3,062 | 2,408 | 9,186 | 7,224 |
| Net periodic benefit cost | $3,857 | $3,465 | $11,571 | $10,391 |

Non-pension Defined Benefit Postretirement Healthcare Plans

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Service cost | $419 | $402 | $1,257 | $1,206 |
| Interest cost | 417 | 523 | 1,251 | 1,569 |
| Expected return on plan assets | (20) | (19) | (60) | (57) |
| Prior service cost (benefit) | (125) | (125) | (375) | (375) |
| Net loss (gain) | 121 | 222 | 363 | 666 |
| Net periodic benefit cost | $812 | $1,003 | $2,436 | $3,009 |

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Service cost | $348 | $243 | $1,044 | $735 |
| Interest cost | 332 | 331 | 996 | 993 |
| Prior service cost | 1 | 1 | 3 | 3 |
| Net loss (gain) | 198 | 202 | 594 | 606 |
| Net periodic benefit cost | $879 | $777 | $2,637 | $2,337 |

Contributions

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

| | Contributions Made Three Months Ended Sept. 30, 2013 | Contributions Made Nine Months Ended Sept. 30, 2013 | Additional Contributions Anticipated for 2013 | Contributions Anticipated for 2014 |
|---|---|---|---|---|
| Defined Benefit Pension Plans | $12,500 | $12,500 | $— | $12,500 |
| Non-pension Defined Benefit Postretirement Healthcare Plans | $784 | $2,352 | $784 | $3,350 |
| Supplemental Non-qualified Defined Benefit and Defined Contribution Plans | $322 | $966 | $322 | $1,463 |

(9) BUSINESS SEGMENT INFORMATION

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

| Three Months Ended Sept. 30, 2013 | External Operating Revenue | Intercompany Operating Revenue | Income (Loss) from Continuing Operations |
|---|---|---|---|
| Utilities: | | | |
| Electric | $169,401 | $2,003 | $15,097 |
| Gas | 67,792 | — | (1,450) |
| Non-regulated Energy: | | | |
| Power Generation | 1,575 | 20,393 | 6,707 |
| Coal Mining | 6,713 | 8,604 | 2,142 |
| Oil and Gas | 14,426 | — | (1,682) |
| Corporate activities [a] | — | — | 2,310 |
| Intercompany eliminations | — | (31,000) | — |
| Total | $259,907 | $— | $23,124 |

| Three Months Ended Sept. 30, 2012 | External Operating Revenue | Intercompany Operating Revenue | Income (Loss) from Continuing Operations |
|---|---|---|---|
| Utilities: | | | |
| Electric | $151,281 | $3,736 | $14,573 |
| Gas | 63,435 | — | 3 |
| Non-regulated Energy: | | | |
| Power Generation | 1,256 | 19,695 | 5,128 |
| Coal Mining | 6,108 | 8,567 | 1,690 |
| Oil and Gas [b] | 24,728 | — | 17,389 |
| Corporate activities [a] | — | — | (4,160) |
| Intercompany eliminations | — | (31,998) | — |
| Total | $246,808 | $— | $34,623 |

| Nine Months Ended Sept. 30, 2013 | External Operating Revenues | Intercompany Operating Revenues | Income (Loss) from Continuing Operations |
|---|---|---|---|
| Utilities: | | | |
| Electric | $482,222 | $9,844 | $38,063 |
| Gas | 373,440 | — | 20,225 |
| Non-regulated Energy: | | | |
| Power Generation | 3,628 | 58,825 | 17,382 |
| Coal Mining | 19,530 | 23,688 | 5,180 |
| Oil and Gas | 41,584 | — | (3,699) |
| Corporate [a] | — | — | 19,688 |
| Intercompany eliminations | — | (92,357) | — |
| Total | $920,404 | $— | $96,839 |

| Nine Months Ended Sept. 30, 2012 | External Operating Revenues | Intercompany Operating Revenues | Income (Loss) from Continuing Operations |
|---|---|---|---|
| Utilities: | | | |
| Electric | $451,974 | $11,946 | $37,478 |
| Gas | 314,343 | — | 16,369 |
| Non-regulated Energy: | | | |
| Power Generation | 3,193 | 56,119 | 15,968 |
| Coal Mining | 18,518 | 24,273 | 3,924 |
| Oil and Gas [b] | 66,994 | — | (2,219) |
| Corporate [a][c] | — | — | (13,949) |
| Intercompany eliminations | — | (92,338) | — |
| Total | $855,022 | $— | $57,571 |

(a) Income (loss) from continuing operations includes a $2.0 million and a $19.1 million net after-tax non-cash mark-to-market gain on certain interest rate swaps for the three and nine months ended Sept. 30, 2013, respectively, and a $0.4 million after-tax non-cash mark-to-market gain and a $1.9 million net after-tax non-cash mark-to-market loss for the three and nine months ended Sept. 30, 2012, respectively, for those same interest rate swaps.

(b) Income (loss) from continuing operations for the nine months ended Sept. 30, 2012, includes a $17.3 million non-cash after-tax ceiling test impairment charge. Income (loss) from continuing operations for the three and nine months ended Sept. 30, 2012, includes an after-tax gain of $17.7 million relating to the sale of the Williston Basin assets. See Notes 14 and 15 for further information.

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

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

| Total Assets (net of inter-company eliminations) as of: | Sept. 30, 2013 | Dec. 31, 2012 | Sept. 30, 2012 |
|---|---|---|---|
| Utilities: | | | |
| Electric [(a)] | $2,464,123 | $2,387,458 | $2,302,951 |
| Gas | 757,746 | 765,165 | 710,099 |
| Non-regulated Energy: | | | |
| Power Generation [(a)] | 102,331 | 119,170 | 119,489 |
| Coal Mining | 82,155 | 83,810 | 90,444 |
| Oil and Gas | 264,785 | 258,460 | 263,088 |
| Corporate activities | 130,100 | 115,408 | 367,557 |
| Total assets | $3,801,240 | $3,729,471 | $3,853,628 |

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

## (10) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2012 Annual Report on Form 10-K.

### Market Risk

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks including, but not limited to:

- Commodity price risk associated with our natural long position in crude oil and natural gas reserves and production and our fuel procurement for certain of our gas-fired generation assets; and

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

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

As of Sept. 30, 2013, our credit exposure included a $1.3 million exposure to a non-investment grade energy marketing company. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade rated companies, cooperative utilities and federal agencies. Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and in Note 11.

Oil and Gas

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

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

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

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

| | Sept. 30, 2013 | | Dec. 31, 2012 | | Sept. 30, 2012 | |
|---|---|---|---|---|---|---|
| | Crude oil futures, swaps and options | Natural gas futures and swaps | Crude oil futures, swaps and options | Natural gas futures and swaps | Crude oil futures, swaps and options | Natural gas futures and swaps |
| Notional [(a)] | 499,500 | 9,874,000 | 528,000 | 8,215,500 | 537,000 | 7,455,250 |
| Maximum terms in years [(b)] | 0.25 | 0.08 | 1.00 | 0.75 | 1.00 | 1.00 |
| Derivative assets, current | $13 | $113 | $1,405 | $1,831 | $1,651 | $2,032 |
| Derivative assets, non-current | $— | $— | $297 | $170 | $494 | $39 |
| Derivative liabilities, current | $98 | $52 | $847 | $507 | $527 | $1,040 |
| Derivative liabilities, non-current | $— | $— | $— | $— | $414 | $141 |

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

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

Based on market prices at Sept. 30, 2013, a $0.1 million gain would be reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Condensed Consolidated Balance Sheets in accordance with state commission guidelines. Accordingly, the hedging activity is recognized in the Condensed Consolidated Statements of Income (Loss) or the Condensed Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

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

| | Sept. 30, 2013 | | Dec. 31, 2012 | | Sept. 30, 2012 | |
|---|---|---|---|---|---|---|
| | Notional (MMBtus) | Maximum Term (months) | Notional (MMBtus) | Maximum Term (months) | Notional (MMBtus) | Maximum Term (months) |
| Natural gas futures purchased | 14,010,000 | 74 | 15,350,000 | 83 | 14,690,000 | 75 |
| Natural gas options purchased | 6,810,000 | 6 | 2,430,000 | 2 | 5,560,000 | 6 |
| Natural gas basis swaps purchased | 9,790,000 | 63 | 12,020,000 | 72 | 8,800,000 | 75 |

We had the following derivative balances related to the hedges in our Utilities reflected in our Condensed Consolidated Balance Sheet as of (in thousands):

| | Sept. 30, 2013 | Dec. 31, 2012 | Sept. 30, 2012 |
|---|---|---|---|
| Derivative assets, current | $— | $— | $12,380 |
| Derivative assets, non-current | $— | $43 | $634 |
| Derivative liabilities, non-current | $— | $— | $4,527 |
| Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities | $10,652 | $9,596 | $9,318 |

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheet were as follows (dollars in thousands) as of:

| | Sept. 30, 2013 | | Dec. 31, 2012 | | Sept. 30, 2012 | |
|---|---|---|---|---|---|---|
| | Designated Interest Rate Swaps (a) | De-designated Interest Rate Swaps (b) | Designated Interest Rate Swaps (a) | De-designated Interest Rate Swaps (b) | Designated Interest Rate Swaps (a) | De-designated Interest Rate Swaps (b) |
| Notional | $150,000 | $250,000 | $150,000 | $250,000 | $150,000 | $250,000 |
| Weighted average fixed interest rate | 5.04 % | 5.67 % | 5.04 % | 5.67 % | 5.04 % | 5.67 % |
| Maximum terms in years | 3.25 | 0.25 | 4.00 | 1.00 | 4.25 | 1.25 |
| Derivative liabilities, current | $7,039 | $58,755 | $7,039 | $88,148 | $7,028 | $77,914 |
| Derivative liabilities, non-current | $11,388 | $— | $16,941 | $— | $18,660 | $17,668 |

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(a) These swaps have been designated to $75.0 million of borrowings on our Revolving Credit Facility and $75.0 million of borrowings on our project financing debt at Black Hills Wyoming. The swaps that hedge the variable rate debt at Black Hills Wyoming were transferred from BHC. Both BHC and Black Hills Wyoming are jointly and severally obligated for the swaps' obligations. These swaps are priced using three-month LIBOR, matching the floating portion of the related swaps.

(b) Maximum terms in years reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. If extended, de-designated swaps totaling $100.0 million notional terminate in approximately 5.25 years and de-designated swaps totaling $150.0 million notional terminate in approximately 15.25 years.

Collateral requirements based on our corporate credit rating apply to $50.0 million of our de-designated swaps. At our current credit ratings, we are required to post collateral for any amount by which the swaps' negative mark-to-market fair value exceeds $20.0 million. If our senior unsecured credit rating drops to BB+ or below by S&P, or to Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swaps' negative mark-to-market fair value. We had approximately $6.0 million cash collateral posted at Sept. 30, 2013.

Based on Sept. 30, 2013, market interest rates and balances related to our designated interest rate swaps, a loss of approximately $7.0 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

## (11) FAIR VALUE MEASUREMENTS

### Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information see Notes 1, 3 and 4 to the Consolidated Financial Statements included in our 2012 Annual Report on Form 10-K filed with the SEC.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

### Valuation Methodologies for Derivatives

Oil and Gas Segment:

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

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

Utilities Segments:

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

Corporate Activities:

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

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

The following tables set forth by level within the fair value hierarchy our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments. A discussion of fair value of financial instruments is included in Note 12:

| | As of Sept. 30, 2013 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | $— | $2 | $— | $— | $2 |
| Basis Swaps -- Oil | — | 51 | — | (40) | 11 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 1,752 | — | (1,639) | 113 |
| Commodity derivatives — Utilities | — | 2,351 | — | (2,351) | — |
| Total | $13,637 | $4,156 | $— | $(4,030) | $126 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | $— | $142 | $— | $(77) | $65 |
| Basis Swaps -- Oil | — | 1,318 | — | (1,284) | 34 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 232 | — | (181) | 51 |
| Commodity derivatives — Utilities | — | 10,747 | — | (10,747) | — |
| Interest rate swaps | — | 83,142 | — | (5,960) | 77,182 |
| Total | $— | $95,581 | $— | $(18,249) | $77,332 |

| | As of Dec. 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | $— | $378 | $— | $— | $378 |
| Basis Swaps -- Oil | — | 1,325 | — | — | 1,325 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 2,000 | — | — | 2,000 |
| Commodity derivatives —Utilities | — | — | 43 (a) | — | 43 |
| Total | $— | $3,703 | $43 | $— | $3,746 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | $— | $1,131 | $— | $(336) | $795 |
| Basis Swaps -- Oil | — | 502 | — | (450) | 52 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 1,127 | — | (620) | 507 |
| Commodity derivatives — Utilities | — | 10,162 | — | (10,162) | — |
| Interest rate swaps | — | 118,088 | — | (5,960) | 112,128 |
| Total | $— | $131,010 | $— | $(17,528) | $113,482 |

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(a) 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.

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| | As of Sept. 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | $— | $619 | $— | $— | $619 |
| Basis Swaps -- Oil | — | 1,526 | — | — | 1,526 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 2,071 | — | — | 2,071 |
| Commodity derivatives — Utilities | — | (2,760) | 34 (a) | 15,740 | 13,014 |
| Total | $— | $1,456 | $34 | $15,740 | $17,230 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives — Oil and Gas | | | | | |
| Options -- Oil | $— | $885 | $— | $— | $885 |
| Basis Swaps -- Oil | — | 56 | — | — | 56 |
| Options -- Gas | — | — | — | — | — |
| Basis Swaps -- Gas | — | 1,181 | — | — | 1,181 |
| Commodity derivatives — Utilities | — | 4,527 | — | — | 4,527 |
| Interest rate swaps | — | 124,580 | — | (3,310) | 121,270 |
| Total | $— | $131,229 | $— | $(3,310) | $127,919 |

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

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis reflecting the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, however, the amounts do not include net cash collateral on deposit in margin accounts at Sept. 30, 2013, Dec. 31, 2012, and Sept. 30, 2012, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 10.

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

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $846 | $— |
| Commodity derivatives | Derivative assets — non-current | 959 | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,317 |
| Commodity derivatives | Derivative liabilities — non-current | — | 375 |
| Interest rate swaps | Derivative liabilities — current | — | 7,039 |
| Interest rate swaps | Derivative liabilities — non-current | — | 11,388 |
| Total derivatives designated as hedges | | $1,805 | $20,119 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $— | $— |
| Commodity derivatives | Derivative assets — non-current | — | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,795 |
| Commodity derivatives | Derivative liabilities — non-current | — | 6,601 |
| Interest rate swaps | Derivative liabilities — current | — | 64,715 |
| Interest rate swaps | Derivative liabilities — non-current | — | — |
| Total derivatives not designated as hedges | | $— | $73,111 |

As of Dec. 31, 2012

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

As of Sept. 30, 2012

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $3,263 | $— |
| Commodity derivatives | Derivative assets — non-current | 533 | — |
| Commodity derivatives | Derivative liabilities — current | — | 1,534 |
| Commodity derivatives | Derivative liabilities — non-current | — | 555 |
| Interest rate swaps | Derivative liabilities — current | — | 7,029 |
| Interest rate swaps | Derivative liabilities — non-current | — | 18,661 |
| Total derivatives designated as hedges | | $3,796 | $27,779 |
| | | | |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | $421 | $3,361 |
| Commodity derivatives | Derivative assets — non-current | — | (634) |
| Commodity derivatives | Derivative liabilities — current | — | 33 |
| Commodity derivatives | Derivative liabilities — non-current | — | 4,527 |
| Interest rate swaps | Derivative liabilities — current | — | 77,913 |
| Interest rate swaps | Derivative liabilities — non-current | — | 20,977 |
| Total derivatives not designated as hedges | | $421 | $106,177 |

Derivatives Offsetting

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

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Condensed Consolidated Balance Sheets in the following tables includes the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at Sept. 30, 2013, Dec. 31, 2012, and Sept. 30, 2012, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Condensed Consolidated Balance Sheets was as follows:

| | As of Sept. 30, 2013 | | |
|---|---|---|---|
| Derivative Assets | Gross Amounts of Derivative Assets | Gross Amounts Offset on Condensed Consolidated Balance Sheets | Net Amount of Total Derivative Assets on Condensed Consolidated Balance Sheets |
| | (in thousands) | | |
| Subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | $40 | $(40) | $— |
| Oil and Gas - Crude Options | — | — | — |
| Oil and Gas - Natural Gas Basis Swaps | 1,639 | (1,639) | — |
| Utilities | 2,351 | (2,351) | — |
| Total derivative assets subject to a master netting agreement or similar arrangement | 4,030 | (4,030) | — |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 11 | — | 11 |
| Oil and Gas - Crude Options | 2 | — | 2 |
| Oil and Gas - Natural Gas Basis Swaps | 113 | — | 113 |
| Utilities | — | — | — |
| Total derivative assets not subject to a master netting agreement or similar arrangement | 126 | — | 126 |
| Total derivative assets | $4,156 | $(4,030) | $126 |

| Derivative Liabilities | As of Sept. 30, 2013<br>Gross Amounts of Derivative Liabilities | Gross Amounts Offset on Condensed Consolidated Balance Sheets | Net Amount of Total Derivative Liabilities on Condensed Consolidated Balance Sheets |
|---|---|---|---|
| | (in thousands) | | |
| Subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | $1,284 | $(1,284) | $— |
| Oil and Gas - Crude Options | 77 | (77) | — |
| Oil and Gas - Natural Gas Basis Swaps | 181 | (181) | — |
| Utilities | 10,747 | (10,747) | — |
| Interest Rate Swaps | — | — | — |
| Total derivative liabilities subject to a master netting agreement or similar arrangement | 12,289 | (12,289) | — |
| | | | |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 34 | — | 34 |
| Oil and Gas - Crude Options | 65 | — | 65 |
| Oil and Gas - Natural Gas Basis Swaps | 51 | — | 51 |
| Utilities | — | — | — |
| Interest Rate Swaps | 83,142 | (5,960) | 77,182 |
| Total derivative liabilities not subject to a master netting agreement or similar arrangement | 83,292 | (5,960) | 77,332 |
| | | | |
| Total derivative liabilities | $95,581 | $(18,249) | $77,332 |

| Derivative Assets | As of Dec. 31, 2012<br>Gross Amounts of Derivative Assets | Gross Amounts Offset on Condensed Consolidated Balance Sheets | Net Amount of Total Derivative Assets on Condensed Consolidated Balance Sheets |
|---|---|---|---|
| | (in thousands) | | |
| Subject to master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | $76 | $— | $76 |
| Oil and Gas - Crude Options | 93 | — | 93 |
| Oil and Gas - Natural Gas Basis Swaps | 172 | — | 172 |
| Utilities | 1,629 | (1,586) | 43 |
| Total derivative assets subject to a master netting agreement or similar arrangement | 1,970 | (1,586) | 384 |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 1,249 | — | 1,249 |
| Oil and Gas - Crude Options | 285 | — | 285 |
| Oil and Gas - Natural Gas Basis Swaps | 1,828 | — | 1,828 |
| Utilities | — | — | — |
| Total derivative assets not subject to a master netting agreement or similar arrangement | 3,362 | — | 3,362 |
| Total derivative assets | $5,332 | $(1,586) | $3,746 |

| Derivative Liabilities | As of Dec. 31, 2012<br>Gross Amounts of Derivative Liabilities | Gross Amounts Offset on Condensed Consolidated Balance Sheets | Net Amount of Total Derivative Liabilities on Condensed Consolidated Balance Sheets |
|---|---|---|---|
| | (in thousands) | | |
| Subject to a master netting agreement or similar arrangement | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | $449 | $(449) | $— |
| Oil and Gas - Crude Options | 337 | (337) | — |
| Oil and Gas - Natural Gas Basis Swaps | 620 | (620) | — |
| Utilities | 10,162 | (10,162) | — |
| Interest Rate Swaps | — | — | — |
| Total derivative liabilities subject to a master netting agreement or similar arrangement | 11,568 | (11,568) | — |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 52 | — | 52 |
| Oil and Gas - Crude Options | 795 | — | 795 |
| Oil and Gas - Natural Gas Basis Swaps | 507 | — | 507 |
| Utilities | — | — | — |
| Interest Rate Swaps | 118,088 | (5,960) | 112,128 |
| Total derivative liabilities not subject to a master netting agreement or similar arrangement | 119,442 | (5,960) | 113,482 |
| Total derivative liabilities | $131,010 | $(17,528) | $113,482 |

| Derivative Assets | As of Sept. 30, 2012<br>Gross Amounts of Derivative Assets | Gross Amounts Offset on Condensed Consolidated Balance Sheets | Net Amount of Total Derivative Assets on Condensed Consolidated Balance Sheets |
|---|---|---|---|
| | (in thousands) | | |
| Subject to master netting agreements or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | $95 | $— | $95 |
| Oil and Gas - Crude Options | 194 | — | 194 |
| Oil and Gas - Natural Gas Basis Swaps | 5 | — | 5 |
| Utilities | (2,726) | 15,740 | 13,014 |
| Total derivative assets subject to a master netting agreement or similar arrangement | (2,432) | 15,740 | 13,308 |
| | | | |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 1,431 | — | 1,431 |
| Oil and Gas - Crude Options | 425 | — | 425 |
| Oil and Gas - Natural Gas Basis Swaps | 2,066 | — | 2,066 |
| Utilities | — | — | — |
| Total derivative assets not subject to a master netting agreement or similar arrangement | 3,922 | — | 3,922 |
| | | | |
| Total derivative assets | $1,490 | $15,740 | $17,230 |

| Derivative Liabilities | As of Sept. 30, 2012 Gross Amounts of Derivative Liabilities | Gross Amounts Offset on Condensed Consolidated Balance Sheets | Net Amount of Total Derivative Liabilities on Condensed Consolidated Balance Sheets |
|---|---|---|---|
| | (in thousands) | | |
| Subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | $— | $— | $— |
| Oil and Gas - Crude Options | — | — | — |
| Oil and Gas - Natural Gas Basis Swaps | — | — | — |
| Utilities | 4,527 | — | 4,527 |
| Interest Rate Swaps | — | — | — |
| Total derivative liabilities subject to a master netting agreement or similar arrangement | 4,527 | — | 4,527 |
| | | | |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 56 | — | 56 |
| Oil and Gas - Crude Options | 885 | — | 885 |
| Oil and Gas - Natural Gas Basis Swaps | 1,181 | — | 1,181 |
| Utilities | — | — | — |
| Interest Rate Swaps | 124,580 | (3,310) | 121,270 |
| Total derivative liabilities not subject to a master netting agreement or similar arrangement | 126,702 | (3,310) | 123,392 |
| | | | |
| Total derivative liabilities | $131,229 | $(3,310) | $127,919 |

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

| | | As of Sept. 30, 2013 | | |
|---|---|---|---|---|
| | | | Gross Amounts Not Offset on Condensed Consolidated Balance Sheets | |
| Contract Type | | Net Amount of Total Derivative Assets | Cash Collateral Received | Net Amount with Counterparty |
| Asset: | | | | |
| Oil and Gas | Counterparty A | $— | $— | $— |
| Oil and Gas | Counterparty B | 126 | — | 126 |
| Utilities | Counterparty A | — | — | — |
| | | $126 | $— | $126 |

| | | As of Sept. 30, 2013 | | |
|---|---|---|---|---|
| | | | Gross Amounts Not Offset on Condensed Consolidated Balance Sheets | |
| Contract Type | | Net Amount of Total Derivative Liabilities | Cash Collateral Posted | Net Amount with Counterparty |
| Liabilities | | | | |
| Oil and Gas | Counterparty A | $— | $(355) | $(355) |
| Oil and Gas | Counterparty B | 150 | — | 150 |
| Utilities | Counterparty A | — | (3,333) | (3,333) |
| Interest Rate Swap | Counterparty D | 3,563 | — | 3,563 |
| Interest Rate Swap | Counterparty E | 19,993 | — | 19,993 |
| Interest Rate Swap | Counterparty F | 9,858 | — | 9,858 |
| Interest Rate Swap | Counterparty G | 20,138 | — | 20,138 |
| Interest Rate Swap | Counterparty H | 8,857 | — | 8,857 |
| Interest Rate Swap | Counterparty I | 14,773 | — | 14,773 |
| | | $77,332 | $(3,688) | $73,644 |

| Contract Type | | As of Dec. 31, 2012<br>Net Amount of Total Derivative Assets | Gross Amounts Not Offset on Condensed Consolidated Balance Sheets<br>Cash Collateral Received | Net Amount with Counterparty |
|---|---|---|---|---|
| Assets: | | | | |
| Oil and Gas | Counterparty A | $341 | $— | $341 |
| Oil and Gas | Counterparty B | 3,362 | — | 3,362 |
| Utilities | Counterparty A | 43 | — | 43 |
| | | $3,746 | $— | $3,746 |

| Contract Type | | As of Dec. 31, 2012<br>Net Amount of Total Derivative Liabilities | Gross Amounts Not Offset on Condensed Consolidated Balance Sheets<br>Cash Collateral Posted | Net Amount with Counterparty |
|---|---|---|---|---|
| Liabilities: | | | | |
| Oil and Gas | Counterparty A | $— | $(1,787) | $(1,787) |
| Oil and Gas | Counterparty B | 1,354 | — | 1,354 |
| Utilities | Counterparty A | — | (4,354) | (4,354) |
| Interest Rate Swap | Counterparty D | 4,588 | — | 4,588 |
| Interest Rate Swap | Counterparty E | 29,245 | — | 29,245 |
| Interest Rate Swap | Counterparty F | 12,721 | — | 12,721 |
| Interest Rate Swap | Counterparty G | 26,520 | — | 26,520 |
| Interest Rate Swap | Counterparty H | 16,809 | — | 16,809 |
| Interest Rate Swap | Counterparty I | 22,245 | — | 22,245 |
| | | $113,482 | $(6,141) | $107,341 |

| | | As of Sept. 30, 2012 | | |
|---|---|---|---|---|
| | | | Gross Amounts Not Offset on Condensed Consolidated Balance Sheets | |
| Contract Type | | Net Amount of Total Derivative Assets | Cash Collateral Received | Net Amount with Counterparty |
| Assets: | | | | |
| Oil and Gas | Counterparty A | $294 | $(2,414) | $(2,120) |
| Oil and Gas | Counterparty B | 3,922 | — | 3,922 |
| Utilities | Counterparty A | 13,014 | — | 13,014 |
| | | $17,230 | $(2,414) | $14,816 |

| | | As of Sept. 30, 2012 | | |
|---|---|---|---|---|
| | | | Gross Amounts Not Offset on Condensed Consolidated Balance Sheets | |
| Contract Type | | Net Amount of Total Derivative Liabilities | Cash Collateral Posted | Net Amount with Counterparty |
| Liabilities: | | | | |
| Oil and Gas | Counterparty A | $— | $— | $— |
| Oil and Gas | Counterparty B | 2,122 | — | 2,122 |
| Utilities | Counterparty A | 4,527 | — | 4,527 |
| Interest Rate Swap | Counterparty D | 4,903 | — | 4,903 |
| Interest Rate Swap | Counterparty E | 31,147 | — | 31,147 |
| Interest Rate Swap | Counterparty F | 13,554 | — | 13,554 |
| Interest Rate Swap | Counterparty G | 27,610 | — | 27,610 |
| Interest Rate Swap | Counterparty H | 20,331 | — | 20,331 |
| Interest Rate Swap | Counterparty I | 23,725 | — | 23,725 |
| | | $127,919 | $— | $127,919 |

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

Cash Flow Hedges

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

Three Months Ended Sept. 30, 2013

| Derivatives in Cash Flow Hedging Relationships | Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion) | Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) | Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion) | Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) | Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) |
|---|---|---|---|---|---|
| Interest rate swaps | $(907) | Interest expense | $(1,844) | | $— |
| Commodity derivatives | (2,140) | Revenue | (168) | | — |
| Total | $(3,047) | | $(2,012) | | $— |

Three Months Ended Sept. 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 | $(1,684) | Interest expense | $(1,853) | | $— |
| Commodity derivatives | (3,111) | Revenue | 1,838 | | — |
| Total | $(4,795) | | $(15) | | $— |

Nine Months Ended Sept. 30, 2013

| Derivatives in Cash Flow Hedging Relationships | Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion) | Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) | Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion) | Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) | Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) |
|---|---|---|---|---|---|
| Interest rate swaps | $141 | Interest expense | $(5,460) | | $— |
| Commodity derivatives | 86 | Revenue | 896 | | — |
| Total | $227 | | $(4,564) | | $— |

Nine Months Ended Sept. 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 | $(4,697) | Interest expense | $(5,518) | | $— |
| Commodity derivatives | 601 | Revenue | 7,741 | | — |
| Total | $(4,096) | | $2,223 | | $— |

Derivatives Not Designated as Hedge Instruments

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

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended Sept. 30, 2013 Amount of Gain/(Loss) on Derivatives Recognized in Income | Nine Months Ended Sept. 30, 2013 Amount of Gain/(Loss) on Derivatives Recognized in Income |
|---|---|---|---|
| Interest rate swaps - unrealized | Unrealized gain (loss) on interest rate swaps, net | $3,144 | $29,393 |
| Interest rate swaps - realized | Interest expense | (3,300) | (10,056) |
| | | $(156) | $19,337 |

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended Sept. 30, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income | Nine Months Ended Sept. 30, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income |
|---|---|---|---|
| Interest rate swaps - unrealized | Unrealized gain (loss) on interest rate swaps, net | $605 | $(2,902) |
| Interest rate swaps - realized | Interest expense | (3,250) | (9,697) |
| Commodity derivatives | Revenue | (14) | (14) |
| | | $(2,659) | $(12,613) |

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 11, were as follows (in thousands) as of:

| | Sept. 30, 2013 | | Dec. 31, 2012 | | Sept. 30, 2012 | |
|---|---|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents [a] | $13,637 | $13,637 | $15,462 | $15,462 | $247,192 | $247,192 |
| Restricted cash and equivalents [a] | $6,782 | $6,782 | $7,916 | $7,916 | $7,302 | $7,302 |
| Notes receivable included in Other current assets[a] | $— | $— | $— | $— | $21,832 | $21,832 |
| Notes payable [a] | $138,300 | $138,300 | $277,000 | $277,000 | $225,000 | $225,000 |
| Long-term debt, including current maturities [b] | $1,211,673 | $1,325,729 | $1,042,850 | $1,231,559 | $1,271,260 | $1,471,932 |

__________

(a) Carrying value approximates fair value due to either the short-term length of maturity or variable interest rates that approximate prevailing market rates, and therefore is classified in Level 1 in the fair value hierarchy.

(b) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(13) COMMITMENTS AND CONTINGENCIES

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 2012 Annual Report on Form 10-K except for those described below.

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

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

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

Purchase and Sale Agreement

On May 6, 2013, Black Hills Wyoming entered into an agreement to sell its 40 megawatt CTII natural gas-fired generating unit to the City of Gillette, Wyo. for approximately $22 million, subject to closing adjustments. The sale is expected to close in August 2014 upon the expiration of an existing power sales agreement with Cheyenne Light under which Black Hills Wyoming sells the output of the CTII to Cheyenne Light. The sale is subject to FERC approval and certain other requirements included in the contract.

Other Commitments

Construction of Cheyenne Prairie, a 132 megawatt natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by Sept. 30, 2014. As of Sept. 30, 2013, committed contracts for equipment purchases and for construction were 94 percent and 67 percent complete, respectively.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills. Black Hills Power subsequently received written damage claims from the State of Wyoming and one landowner seeking recovery for alleged injury to timber, grass, fencing, fire suppression and rehabilitation costs of approximately $8 million. On April 16, 2013, thirty-four private landowners filed suit in United States District Court for the District of Wyoming, asserting similar claims, based upon allegations of negligence, common law nuisance and trespass. The suit seeks recovery of both actual and punitive damages in an unspecified amount. Our investigation into the cause and origin of the fire is pending. We expect to deny and will vigorously defend all claims arising out of the lawsuit, pending the completion of our investigation. Given the uncertainty of litigation, however, a loss related to the fire and the litigation is reasonably possible. We cannot reasonably estimate the amount of a potential loss because our investigation is ongoing. Further claims may be presented by other parties. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation. Based on information currently available, however, management does not expect the claims, if determined adversely to us, to have a material adverse effect on our financial condition or results of operations.

Sale of Enserco Energy Inc.

After the sale of Enserco, our Energy Marketing segment, on Feb. 29, 2012, and pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments, which we disputed. The buyer filed a petition in the Colorado District Court for the City and County of Denver, Colo., seeking an order compelling binding arbitration on all of the disputed claims. Following a hearing in July 2013, the court entered an order remanding all but one of the disputed adjustment claims to arbitration.  We continue to dispute the validity of the adjustment claims within the arbitration process, which we expect will conclude before the end of 2013.

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 Sept. 30, 2013, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at Sept. 30, 2013:

- Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of Sept. 30, 2013, the restricted net assets at our Utilities Group were approximately $148.6 million.

- As required by a covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has maintained restricted shareholders' equity of at least $100 million.

Guarantees

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

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

(14) SALE OF ASSETS

Oil and Gas

On Sept. 27, 2012, our Oil and Gas segment sold a majority of its Bakken and Three Forks shale assets in the Williston Basin of North Dakota. An effective date of July 1, 2012, was used to determine the sales price.

Our Oil and Gas segment follows the full-cost method of accounting for oil and gas activities. Typically, this methodology does not allow for gain or loss on sale and proceeds from sale are credited against the full cost pool. Gain or loss recognition is allowed when such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Williston Basin asset sale significantly altered the relationship and accordingly we recorded a gain of $27.3 million with the remainder of the proceeds recorded as a reduction in the full cost pool. This reduction in the full cost pool temporarily decreased the depreciation, depletion and amortization rate.

Net cash proceeds, subsequent to the true-up of all post-closing adjustments, were as follows (in thousands):

| | |
|---|---|
| Cash proceeds received on date of sale | $243,314 |
| | |
| Adjustments to proceeds: | |
| Final post close adjustments | 2,793 |
| Transaction adviser fees | (1,400) |
| Payment for contractual obligation related to "back-in" fee * | (16,847) |
| | |
| Final net cash proceeds | $227,860 |

* Required payment, triggered by the sale of the property, arising from a contractual obligation contained in the original participation agreement with the property operator.

Electric Utilities

On Sept. 18, 2012, Colorado Electric completed the sale of an undivided 50 percent ownership interest in the 29 megawatt Busch Ranch Wind project to AltaGas for $25 million. Colorado Electric retains the remaining undivided interest and is the operator of this jointly owned facility. Commercial operation of the newly constructed wind farm was achieved on Oct. 16, 2012.

## (15) IMPAIRMENT OF LONG-LIVED ASSETS

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

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

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

We are an integrated energy company operating principally in the United States with two major business groups — Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

| Business Group | Financial Segment |
|---|---|
| Utilities | Electric Utilities<br>Gas Utilities |
| Non-regulated Energy | Power Generation<br>Coal Mining<br>Oil and Gas |

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 202,000 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 35,000 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 532,000 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Power Generation, Coal Mining and Oil and Gas segments. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyo. and sells the coal primarily to on-site, mine-mouth power generation facilities. Our Oil and Gas segment engages in exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment’s peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended Sept. 30, 2013 and 2012, and our financial condition as of Sept. 30, 2013, Dec. 31, 2012, and Sept. 30, 2012, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.
See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 82.

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

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended Sept. 30, 2013 Compared to Three Months Ended Sept. 30, 2012. Income from continuing operations for the three months ended Sept. 30, 2013 was $23.1 million, or $0.52 per share, compared to Income from continuing operations of $34.6 million, or $0.78 per share, reported for the same period in 2012. Net income for the three months ended Sept. 30, 2013 was $23.1 million, or $0.52 per share, compared to Net income of $34.5 million, or $0.78 per share, for the same period in 2012.

Nine Months Ended Sept. 30, 2013 Compared to Nine Months Ended Sept. 30, 2012. Income from continuing operations for the nine months ended Sept. 30, 2013 was $96.8 million, or $2.18 per share, compared to Income from continuing operations of $57.6 million, or $1.31 per share, reported for the same period in 2012. Net income for the nine months ended Sept. 30, 2013 was $96.8 million, or $2.18 per share, compared to Net income of $50.8 million, or $1.15 per share, for the same period in 2012.

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

| | Three Months Ended Sept. 30, | | | Nine Months Ended Sept. 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | 2013 | 2012 | Variance |
| Revenue | | | | | | |
| Utilities | $239,196 | $218,452 | $20,744 | $865,506 | $778,263 | $87,243 |
| Non-regulated Energy | 51,711 | 60,354 | (8,643) | 147,255 | 169,097 | (21,842) |
| Intercompany eliminations | (31,000) | (31,998) | 998 | (92,357) | (92,338) | (19) |
| | $259,907 | $246,808 | $13,099 | $920,404 | $855,022 | $65,382 |
| Net income (loss) | | | | | | |
| Electric Utilities | $15,097 | $14,573 | $524 | $38,063 | $37,478 | $585 |
| Gas Utilities | (1,450) | 3 | (1,453) | 20,225 | 16,369 | 3,856 |
| Utilities | 13,647 | 14,576 | (929) | 58,288 | 53,847 | 4,441 |
| Power Generation | 6,707 | 5,128 | 1,579 | 17,382 | 15,968 | 1,414 |
| Coal Mining | 2,142 | 1,690 | 452 | 5,180 | 3,924 | 1,256 |
| Oil and Gas [a] | (1,682) | 17,389 | (19,071) | (3,699) | (2,219) | (1,480) |
| Non-regulated Energy | 7,167 | 24,207 | (17,040) | 18,863 | 17,673 | 1,190 |
| Corporate activities and eliminations [b][c] | 2,310 | (4,160) | 6,470 | 19,688 | (13,949) | 33,637 |
| Income (loss) from continuing operations | 23,124 | 34,623 | (11,499) | 96,839 | 57,571 | 39,268 |
| Income (loss) from discontinued operations, net of tax | — | (166) | 166 | — | (6,810) | 6,810 |
| Net income (loss) | $23,124 | $34,457 | $(11,333) | $96,839 | $50,761 | $46,078 |

(a) Income (loss) from continuing operations for the three months and nine months ended Sept. 30, 2012 includes an after-tax gain of $17.7 million relating to the sale of the Williston Basin assets. Income (loss) from continuing operations for nine months ended Sept. 30, 2012 includes a $17.3 million non-cash after-tax ceiling test impairment. See Notes 14 and 15 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

(b)

Corporate activities include a \$2.0 million and a \$19.1 million net after-tax non-cash mark-to-market gain on certain interest rate swaps for the three and nine months ended Sept. 30, 2013, respectively, and a \$0.4 million net after-tax non-cash mark-to-market gain and a \$1.9 million net after-tax non-cash mark-to-market loss for the three and nine months ended Sept. 30, 2012, respectively, for those same interest rate swaps.

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

Overview of Business Segments and Corporate Activity

Utilities Group

- On Sept. 17, 2013, the SDPUC approved a construction financing rider for the South Dakota portion of costs for Cheyenne Prairie in lieu of the typical AFUDC, with an effective date of April 1, 2013. The WPSC approved a similar construction financing rider for our Wyoming customers during 2012. The riders allow Black Hills Power and Cheyenne Light to recover financing costs during the construction period, while reducing the overall capital costs of the project. The Electric Utilities recorded additional gross margins of approximately $2.7 million and $5.0 million for the three and nine months ended Sept. 30, 2013, respectively, relating to these riders.

- On Sept. 17, 2013, the SDPUC approved an annual rate increase of $8.8 million, or 6.4 percent, effective June 16, 2013 for Black Hills Power.

- Construction and infrastructure work for Cheyenne Prairie, a natural gas-fired electric generating facility to serve Cheyenne Light and Black Hills Power customers, began in April 2013. The 132 megawatt generation project is expected to cost approximately $222 million, exclusive of construction financing costs which will be recovered through the construction financing riders. Project to date, we have expended approximately $122 million. The project is on schedule to be placed into service in the fourth quarter of 2014.

- Gas Utilities results were favorably impacted by colder weather during 2013. Heating degree days were 33 percent higher for the nine months ended Sept. 30, 2013, compared to the same periods in 2012. Heating degree days for the nine months ended Sept. 30, 2013 were 8 percent higher than normal, compared to 21 percent lower than normal for the same periods in 2012.

- On April 30, 2013, Colorado Electric filed its electric resource plan with the CPUC, addressing its projected resource requirements through 2019. The resource plan identifies a 40 megawatt, simple-cycle, natural gas-fired turbine as the replacement capacity for the retirement of the coal-fired, 42 megawatt W.N. Clark power plant. A CPCN was submitted with the CPUC requesting approval for the new generating capacity. The resource plan also recommends the retirement of Pueblo Units 5 and 6 as of Dec. 31, 2013. A CPCN was submitted to the CPUC seeking approval to retire these plants. A hearing with the CPUC is scheduled in November 2013 regarding the resource plan and the two CPCNs.

- On Oct. 16, the CPUC denied Colorado Electric's application for approval of a wind solicitation for the acquisition of up to 30 megawatts of wind energy for its electric system. This solicitation and related requests for proposal were reviewed by an independent evaluator who verified that our Power Generation segment's bid was the lowest cost to customers. The CPUC found that the calculated customer benefits over the 20 year evaluation period were insufficient for all of the bids and stated its preference to consider renewable energy needs in Colorado Electric's upcoming Electric Resource Plan hearings scheduled for November 2013.

- Gas Utilities continued its efforts to acquire small municipal gas distribution systems adjacent to our existing Gas Utility service territories. Four small gas systems have been acquired in 2013, adding approximately 900 customers.

Non-regulated Energy Group

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

- Oil and Gas reported a 32 percent and 31 percent reduction in total volumes sold for the three and nine months ended Sept. 30, 2013, respectively, reflecting the 2012 sale of the Williston Basin oil and gas assets. Oil and Gas results benefited from a 6 percent and 13 percent increase in average hedge price received for crude oil during the three and nine months ended Sept. 30, 2013, respectively, compared to the same periods in 2012, partially offset by an 8 percent and 18 percent decrease in average hedge price received for natural gas for those same periods.

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

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

Corporate Activities

- On Sept. 25, 2013, Moody’s raised our corporate credit rating to Baa2 from Baa3 with continued positive outlook. On July 24, 2013, S&P raised our corporate credit rating to BBB from BBB- with a stable outlook. They also raised our senior unsecured rating to BBB from BBB-. On May 10, Fitch Ratings raised our Issuer Default Rating to BBB from BBB- with a positive outlook.

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

- Consolidated interest expense decreased by approximately $3.6 million and $14.3 million for the three and nine months ended Sept. 30, 2013, respectively, due primarily to the repayment of approximately $225 million of debt in 2012.

- We recognized a non-cash unrealized mark-to-market gain (loss) related to certain interest rate swaps of $29.4 million and $(2.9) million for the nine months ended Sept. 30, 2013 and 2012, respectively.

Operating Results

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

Utilities Group

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

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors' understanding of our operating performance.

Gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel, purchased power and cost of gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies' gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

| | Three Months Ended Sept. 30, | | | Nine Months Ended Sept. 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | 2013 | 2012 | Variance |
| | (in thousands) | | | | | |
| Revenue — electric | $167,152 | $151,465 | $15,687 | $469,300 | $442,731 | $26,569 |
| Revenue — gas | 4,252 | 3,552 | 700 | 22,766 | 21,189 | 1,577 |
| Total revenue | 171,404 | 155,017 | 16,387 | 492,066 | 463,920 | 28,146 |
| | | | | | | |
| Fuel, purchased power and cost of gas — electric | 70,859 | 65,992 | 4,867 | 203,897 | 191,113 | 12,784 |
| Purchased gas — gas | 1,579 | 1,046 | 533 | 10,532 | 11,087 | (555) |
| Total fuel, purchased power and cost of gas | 72,438 | 67,038 | 5,400 | 214,429 | 202,200 | 12,229 |
| | | | | | | |
| Gross margin — electric | 96,293 | 85,473 | 10,820 | 265,403 | 251,618 | 13,785 |
| Gross margin — gas | 2,673 | 2,506 | 167 | 12,234 | 10,102 | 2,132 |
| Total gross margin | 98,966 | 87,979 | 10,987 | 277,637 | 261,720 | 15,917 |
| | | | | | | |
| Operations and maintenance | 41,145 | 34,080 | 7,065 | 119,363 | 110,176 | 9,187 |
| Depreciation and amortization | 19,368 | 18,821 | 547 | 58,194 | 56,448 | 1,746 |
| Total operating expenses | 60,513 | 52,901 | 7,612 | 177,557 | 166,624 | 10,933 |
| | | | | | | |
| Operating income | 38,453 | 35,078 | 3,375 | 100,080 | 95,096 | 4,984 |
| | | | | | | |
| Interest expense, net | (14,089) | (12,527) | (1,562) | (42,296) | (38,069) | (4,227) |
| Other income (expense), net | 13 | 198 | (185) | 471 | 1,207 | (736) |
| Income tax benefit (expense) | (9,280) | (8,176) | (1,104) | (20,192) | (20,756) | 564 |
| Income (loss) from continuing operations | $15,097 | $14,573 | $524 | $38,063 | $37,478 | $585 |

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| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| Revenue - Electric (in thousands) | 2013 | 2012 | 2013 | 2012 |
| Residential: | | | | |
| Black Hills Power | $16,951 | $15,794 | $46,928 | $43,903 |
| Cheyenne Light | 8,816 | 8,324 | 26,453 | 23,816 |
| Colorado Electric | 27,438 | 26,390 | 73,388 | 70,048 |
| Total Residential | 53,205 | 50,508 | 146,769 | 137,767 |
| | | | | |
| Commercial: | | | | |
| Black Hills Power | 23,319 | 20,336 | 59,716 | 55,948 |
| Cheyenne Light | 14,738 | 13,003 | 41,981 | 42,346 |
| Colorado Electric | 23,531 | 20,898 | 66,345 | 61,595 |
| Total Commercial | 61,588 | 54,237 | 168,042 | 159,889 |
| | | | | |
| Industrial: | | | | |
| Black Hills Power | 6,850 | 5,846 | 20,070 | 18,929 |
| Cheyenne Light | 5,522 | 4,551 | 15,721 | 10,863 |
| Colorado Electric | 9,872 | 8,476 | 29,156 | 27,689 |
| Total Industrial | 22,244 | 18,873 | 64,947 | 57,481 |
| | | | | |
| Municipal: | | | | |
| Black Hills Power | 1,078 | 930 | 2,639 | 2,515 |
| Cheyenne Light | 499 | 454 | 1,447 | 1,352 |
| Colorado Electric | 4,018 | 3,419 | 10,057 | 10,031 |
| Total Municipal | 5,595 | 4,803 | 14,143 | 13,898 |
| | | | | |
| Total Retail Revenue - Electric | 142,632 | 128,421 | 393,901 | 369,035 |
| | | | | |
| Contract Wholesale: | | | | |
| Total Contract Wholesale - Black Hills Power | 5,847 | 5,627 | 16,540 | 14,902 |
| | | | | |
| Off-system Wholesale: | | | | |
| Black Hills Power | 8,123 | 5,599 | 22,222 | 23,331 |
| Cheyenne Light | 1,603 | 1,532 | 6,379 | 6,012 |
| Colorado Electric | 2,035 | 1,663 | 5,275 | 2,073 |
| Total Off-system Wholesale | 11,761 | 8,794 | 33,876 | 31,416 |
| | | | | |
| Other Revenue: | | | | |
| Black Hills Power | 5,100 | 7,002 | 19,802 | 22,248 |
| Cheyenne Light | 594 | 624 | 1,642 | 1,663 |
| Colorado Electric | 1,218 | 997 | 3,539 | 3,467 |
| Total Other Revenue | 6,912 | 8,623 | 24,983 | 27,378 |
| | | | | |
| Total Revenue - Electric | $167,152 | $151,465 | $469,300 | $442,731 |

| Quantities Generated and Purchased (in MWh) | Three Months Ended Sept. 30, 2013 | 2012 | Nine Months Ended Sept. 30, 2013 | 2012 |
|---|---|---|---|---|
| Generated — | | | | |
| Coal-fired: | | | | |
| Black Hills Power [(a)] | 457,329 | 475,752 | 1,334,441 | 1,344,593 |
| Cheyenne Light [(b)] | 185,603 | 155,099 | 513,299 | 436,576 |
| Colorado Electric [(c)] | — | 61,820 | — | 177,712 |
| Total Coal-fired | 642,932 | 692,671 | 1,847,740 | 1,958,881 |
| | | | | |
| Gas, Oil and Wind: | | | | |
| Black Hills Power | 18,275 | 21,543 | 25,953 | 28,122 |
| Cheyenne Light | — | — | — | — |
| Colorado Electric [(d)] | 74,631 | 50,691 | 236,227 | 72,271 |
| Total Gas, Oil and Wind | 92,906 | 72,234 | 262,180 | 100,393 |
| | | | | |
| Total Generated: | | | | |
| Black Hills Power | 475,604 | 497,295 | 1,360,394 | 1,372,715 |
| Cheyenne Light | 185,603 | 155,099 | 513,299 | 436,576 |
| Colorado Electric | 74,631 | 112,511 | 236,227 | 249,983 |
| Total Generated | 735,838 | 764,905 | 2,109,920 | 2,059,274 |
| | | | | |
| Purchased — | | | | |
| Black Hills Power | 361,390 | 280,815 | 1,098,772 | 1,228,072 |
| Cheyenne Light | 180,127 | 191,884 | 586,999 | 604,911 |
| Colorado Electric | 534,830 | 488,321 | 1,402,005 | 1,298,690 |
| Total Purchased | 1,076,347 | 961,020 | 3,087,776 | 3,131,673 |
| | | | | |
| Total Generated and Purchased: | | | | |
| Black Hills Power | 836,994 | 778,110 | 2,459,166 | 2,600,787 |
| Cheyenne Light | 365,730 | 346,983 | 1,100,298 | 1,041,487 |
| Colorado Electric | 609,461 | 600,832 | 1,638,232 | 1,548,673 |
| Total Generated and Purchased | 1,812,185 | 1,725,925 | 5,197,696 | 5,190,947 |

__________

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

(b) Results for the three and nine months ended Sept. 30, 2012 reflect a planned and extended overhaul at Wygen II.

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

(d) Increase was primarily due to the addition of energy from the Busch Ranch wind project, which was placed into commercial operation in the fourth quarter of 2012 and higher usage of our gas-fired generation at the Pueblo Airport Generating Facility as a result of the suspension of operations at W.N. Clark as of Dec. 31, 2012 and a decrease in the amount of economy energy available to purchase from third parties.

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| Quantity Sold (in MWh) | 2013 | 2012 | 2013 | 2012 |
| Residential: | | | | |
| Black Hills Power | 131,664 | 139,282 | 406,159 | 396,267 |
| Cheyenne Light | 66,278 | 68,816 | 202,403 | 197,093 |
| Colorado Electric | 178,187 | 185,696 | 474,378 | 476,425 |
| Total Residential | 376,129 | 393,794 | 1,082,940 | 1,069,785 |
| | | | | |
| Commercial: | | | | |
| Black Hills Power | 201,332 | 202,418 | 551,712 | 553,792 |
| Cheyenne Light | 136,062 | 141,433 | 397,705 | 449,718 |
| Colorado Electric | 187,770 | 198,839 | 538,815 | 548,964 |
| Total Commercial | 525,164 | 542,690 | 1,488,232 | 1,552,474 |
| | | | | |
| Industrial: | | | | |
| Black Hills Power | 98,174 | 93,147 | 295,662 | 303,906 |
| Cheyenne Light | 74,316 | 62,397 | 209,984 | 151,326 |
| Colorado Electric | 102,156 | 89,305 | 273,572 | 267,739 |
| Total Industrial | 274,646 | 244,849 | 779,218 | 722,971 |
| | | | | |
| Municipal: | | | | |
| Black Hills Power | 10,691 | 11,154 | 26,621 | 27,565 |
| Cheyenne Light | 2,412 | 2,318 | 7,150 | 7,028 |
| Colorado Electric | 38,749 | 35,461 | 85,844 | 95,649 |
| Total Municipal | 51,852 | 48,933 | 119,615 | 130,242 |
| | | | | |
| Total Retail Quantity Sold | 1,227,791 | 1,230,266 | 3,470,005 | 3,475,472 |
| | | | | |
| Contract Wholesale: | | | | |
| Total Contract Wholesale - Black Hills Power | 87,092 | 88,334 | 268,529 | 249,388 |
| | | | | |
| Off-system Wholesale: | | | | |
| Black Hills Power | 261,567 | 190,143 | 777,854 | 943,522 |
| Cheyenne Light | 47,120 | 46,157 | 178,942 | 166,777 |
| Colorado Electric | 63,529 | 52,228 | 133,544 | 60,899 |
| Total Off-system Wholesale | 372,216 | 288,528 | 1,090,340 | 1,171,198 |
| | | | | |
| Total Quantity Sold: | | | | |
| Black Hills Power | 790,520 | 724,478 | 2,326,537 | 2,474,440 |
| Cheyenne Light | 326,188 | 321,121 | 996,184 | 971,942 |
| Colorado Electric | 570,391 | 561,529 | 1,506,153 | 1,449,676 |
| Total Quantity Sold | 1,687,099 | 1,607,128 | 4,828,874 | 4,896,058 |
| | | | | |
| Losses and Company Use: | | | | |
| Black Hills Power | 46,474 | 53,632 | 132,629 | 126,347 |
| Cheyenne Light | 39,542 | 25,863 | 104,114 | 69,545 |
| Colorado Electric | 39,070 | 39,302 | 132,079 | 98,997 |
| Total Losses and Company Use | 125,086 | 118,797 | 368,822 | 294,889 |

| | | | | |
|---|---|---|---|---|
| Total Quantity Sold | 1,812,185 | 1,725,925 | 5,197,696 | 5,190,947 |

| Degree Days | Three Months Ended Sept. 30, 2013 | | 2012 | |
|---|---|---|---|---|
| | Actual | Variance from 30-Year Average | Actual | Variance from 30-Year Average |
| Heating Degree Days: | | | | |
| Black Hills Power | 107 | (49)% | 99 | (56)% |
| Cheyenne Light | 182 | (36)% | 170 | (40)% |
| Colorado Electric | 25 | (71)% | 54 | (45)% |
| | | | | |
| Cooling Degree Days: | | | | |
| Black Hills Power | 646 | 15% | 731 | 37% |
| Cheyenne Light | 397 | 32% | 430 | 44% |
| Colorado Electric | 851 | 17% | 898 | 31% |

| Degree Days | Nine Months Ended Sept. 30, 2013 | | 2012 | |
|---|---|---|---|---|
| | Actual | Variance from 30-Year Average | Actual | Variance from 30-Year Average |
| Heating Degree Days: | | | | |
| Black Hills Power | 4,544 | 6% | 3,558 | (50)% |
| Cheyenne Light | 4,665 | 4% | 3,772 | (47)% |
| Colorado Electric | 3,527 | 2% | 2,753 | (51)% |
| | | | | |
| Cooling Degree Days: | | | | |
| Black Hills Power | 724 | 8% | 937 | 47% |
| Cheyenne Light | 520 | 48% | 568 | 63% |
| Colorado Electric | 1,227 | 28% | 1,321 | 47% |

| Electric Utilities Power Plant Availability | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Coal-fired plants | 97.6% | 95.4% | 96.8% | 89.1% [(a)] |
| Other plants | 95.8% | 98.5% | 96.7% | 96.6% |
| Total availability | 96.7% | 97.0% | 96.7% | 93.0% |

(a) Reflects an unplanned outage due to a transformer failure and a planned outage at Neil Simpson II, and a planned and extended overhaul at Wygen II.

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Cheyenne Light Natural Gas Distribution

Included in the Electric Utilities is Cheyenne Light's natural gas distribution system. The following table summarizes certain operating information for these natural gas distribution operations:

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Revenue - Gas (in thousands): | | | | |
| Residential | $2,719 | $2,362 | $14,284 | $12,947 |
| Commercial | 977 | 770 | 6,107 | 5,789 |
| Industrial | 356 | 248 | 1,759 | 1,882 |
| Other Sales Revenue | 200 | 172 | 616 | 571 |
| Total Revenue - Gas | $4,252 | $3,552 | $22,766 | $21,189 |
| | | | | |
| Gross Margin (in thousands): | | | | |
| Residential | $1,977 | $1,864 | $8,611 | $7,092 |
| Commercial | 423 | 417 | 2,663 | 2,141 |
| Industrial | 73 | 53 | 344 | 302 |
| Other Gross Margin | 200 | 172 | 616 | 567 |
| Total Gross Margin | $2,673 | $2,506 | $12,234 | $10,102 |
| | | | | |
| Volumes Sold (Dth): | | | | |
| Residential | 172,136 | 168,229 | 1,757,397 | 1,453,478 |
| Commercial | 128,320 | 119,344 | 1,033,171 | 918,131 |
| Industrial | 66,027 | 64,721 | 430,186 | 411,664 |
| Total Volumes Sold | 366,483 | 352,294 | 3,220,754 | 2,783,273 |

Results of Operations for the Electric Utilities for the Three Months Ended Sept. 30, 2013 Compared to the Three Months Ended Sept. 30, 2012: Income from continuing operations for the Electric Utilities was $15.1 million for the three months ended Sept. 30, 2013, compared to $14.6 million for the three months ended Sept. 30, 2012, as a result of:

Gross margin increased primarily due to a $2.4 million increase from higher electric rates, a $2.7 million increase related to the Cheyenne Prairie construction financing riders, a $1.0 million increase as a result of energy cost adjustments, a $0.5 million increase from wholesale quantities sold, and a $0.7 million increase from transmission riders.

Operations and maintenance increased primarily due to an increase in property taxes, vegetation management and employee compensation and benefit costs. The 2012 period included a $2.1 million reduction for major maintenance accruals relating to plant suspensions and retirements.

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

Interest expense, net increased primarily due to an increase in debt balances and lower AFUDC.

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 Nine Months Ended Sept. 30, 2013 Compared to the Nine Months Ended Sept. 30, 2012: Income from continuing operations for the Electric Utilities was $38.1 million for the nine months ended Sept. 30, 2013, compared to $37.5 million for the nine months ended Sept. 30, 2012, as a result of:

Gross margin increased primarily due to a $3.9 million increase from higher electric rates, a $5.0 million increase related to the Cheyenne Prairie construction financing riders, a $1.9 million increase from transmission riders, a $1.2 million increase from wholesale quantities sold, a $1.0 million increase in gas demand from colder weather, and a $1.0 million increase in gas rates, partially offset by a $0.5 million decrease related to lower electric retail quantities sold and a $0.5 million decrease from off-system sales as a result of lower pricing and quantities sold.

Operations and maintenance increased primarily due to an increase in property taxes, vegetation management and increased employee compensation and benefit costs. Prior year included a $2.1 million reduction for major maintenance accruals relating to plant suspensions and retirements.

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

Interest expense, net increased primarily due to an increase in debt balances and lower AFUDC.

Other income (expense), net included higher AFUDC - equity in the prior year.

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

Gas Utilities

| | Three Months Ended Sept. 30, | | | Nine Months Ended Sept. 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | 2013 | 2012 | Variance |
| | (in thousands) | | | | | |
| Natural gas — regulated | $60,931 | $56,845 | $4,086 | $351,517 | $293,047 | $58,470 |
| Other — non-regulated services | 6,861 | 6,590 | 271 | 21,923 | 21,296 | 627 |
| Total revenue | 67,792 | 63,435 | 4,357 | 373,440 | 314,343 | 59,097 |
| | | | | | | |
| Natural gas — regulated | 23,999 | 20,802 | 3,197 | 197,522 | 154,342 | 43,180 |
| Other — non-regulated services | 3,634 | 3,383 | 251 | 10,868 | 10,272 | 596 |
| Total cost of sales | 27,633 | 24,185 | 3,448 | 208,390 | 164,614 | 43,776 |
| | | | | | | |
| Gross margin | 40,159 | 39,250 | 909 | 165,050 | 149,729 | 15,321 |
| | | | | | | |
| Operations and maintenance | 30,459 | 28,339 | 2,120 | 95,537 | 88,121 | 7,416 |
| Depreciation and amortization | 6,594 | 6,338 | 256 | 19,680 | 18,748 | 932 |
| Total operating expenses | 37,053 | 34,677 | 2,376 | 115,217 | 106,869 | 8,348 |
| | | | | | | |
| Operating income (loss) | 3,106 | 4,573 | (1,467) | 49,833 | 42,860 | 6,973 |
| | | | | | | |
| Interest expense, net | (6,016) | (5,370) | (646) | (18,200) | (17,659) | (541) |
| Other income (expense), net | 26 | (2) | 28 | 33 | 82 | (49) |
| Income tax benefit (expense) | 1,434 | 802 | 632 | (11,441) | (8,914) | (2,527) |
| Income (loss) from continuing operations | $(1,450) | $3 | $(1,453) | $20,225 | $16,369 | $3,856 |

| Revenue (in thousands) | Three Months Ended Sept. 30, 2013 | 2012 | Nine Months Ended Sept. 30, 2013 | 2012 |
|---|---|---|---|---|
| Residential: | | | | |
| Colorado | $5,007 | $4,498 | $34,651 | $33,837 |
| Nebraska | 11,850 | 11,370 | 83,634 | 65,832 |
| Iowa | 10,471 | 9,776 | 67,361 | 56,216 |
| Kansas | 8,166 | 7,354 | 46,551 | 36,537 |
| Total Residential | 35,494 | 32,998 | 232,197 | 192,422 |
| | | | | |
| Commercial: | | | | |
| Colorado | 1,253 | 898 | 6,691 | 6,525 |
| Nebraska | 2,436 | 2,742 | 25,781 | 20,760 |
| Iowa | 4,511 | 3,988 | 30,728 | 24,495 |
| Kansas | 2,208 | 1,973 | 15,049 | 10,702 |
| Total Commercial | 10,408 | 9,601 | 78,249 | 62,482 |
| | | | | |
| Industrial: | | | | |
| Colorado | 900 | 1,110 | 1,455 | 1,756 |
| Nebraska | 242 | 306 | 547 | 735 |
| Iowa | 457 | 357 | 1,911 | 1,551 |
| Kansas | 7,748 | 7,078 | 14,748 | 12,314 |
| Total Industrial | 9,347 | 8,851 | 18,661 | 16,356 |
| | | | | |
| Transportation: | | | | |
| Colorado | 98 | 113 | 726 | 616 |
| Nebraska | 1,958 | 1,866 | 9,069 | 7,337 |
| Iowa | 916 | 816 | 3,454 | 3,044 |
| Kansas | 1,402 | 1,338 | 4,904 | 4,367 |
| Total Transportation | 4,374 | 4,133 | 18,153 | 15,364 |
| | | | | |
| Other Sales Revenue: | | | | |
| Colorado | 17 | 15 | (35) | 65 |
| Nebraska | 491 | 469 | 1,731 | 1,561 |
| Iowa | 120 | 86 | 422 | 350 |
| Kansas | 680 | 692 | 2,139 | 4,447 |
| Total Other Sales Revenue | 1,308 | 1,262 | 4,257 | 6,423 |
| | | | | |
| Total Regulated Revenue | 60,931 | 56,845 | 351,517 | 293,047 |
| | | | | |
| Non-regulated Services | 6,861 | 6,590 | 21,923 | 21,296 |
| | | | | |
| Total Revenue | $67,792 | $63,435 | $373,440 | $314,343 |

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| Gross Margin (in thousands) | 2013 | 2012 | 2013 | 2012 |
| Residential: | | | | |
| Colorado | $2,791 | $2,548 | $12,913 | $11,375 |
| Nebraska | 8,374 | 8,334 | 37,740 | 32,922 |
| Iowa | 8,032 | 7,850 | 31,018 | 28,373 |
| Kansas | 5,915 | 5,622 | 23,044 | 20,537 |
| Total Residential | 25,112 | 24,354 | 104,715 | 93,207 |
| | | | | |
| Commercial: | | | | |
| Colorado | 480 | 399 | 2,048 | 1,818 |
| Nebraska | 1,264 | 1,404 | 8,191 | 7,027 |
| Iowa | 1,924 | 1,890 | 8,968 | 7,723 |
| Kansas | 1,139 | 1,087 | 5,302 | 4,365 |
| Total Commercial | 4,807 | 4,780 | 24,509 | 20,933 |
| | | | | |
| Industrial: | | | | |
| Colorado | 279 | 307 | 467 | 509 |
| Nebraska | 72 | 99 | 157 | 204 |
| Iowa | 43 | 56 | 206 | 172 |
| Kansas | 1,011 | 1,096 | 1,985 | 2,090 |
| Total Industrial | 1,405 | 1,558 | 2,815 | 2,975 |
| | | | | |
| Transportation: | | | | |
| Colorado | 98 | 113 | 726 | 617 |
| Nebraska | 1,958 | 1,866 | 9,069 | 7,337 |
| Iowa | 916 | 816 | 3,454 | 3,044 |
| Kansas | 1,402 | 1,338 | 4,904 | 4,367 |
| Total Transportation | 4,374 | 4,133 | 18,153 | 15,365 |
| | | | | |
| Other Sales Margins: | | | | |
| Colorado | 17 | 15 | (35) | 65 |
| Nebraska | 491 | 469 | 1,731 | 1,562 |
| Iowa | 120 | 86 | 422 | 351 |
| Kansas | 606 | 648 | 1,685 | 4,248 |
| Total Other Sales Margins | 1,234 | 1,218 | 3,803 | 6,226 |
| | | | | |
| Total Regulated Gross Margin | 36,932 | 36,043 | 153,995 | 138,706 |
| | | | | |
| Non-regulated Services | 3,227 | 3,207 | 11,055 | 11,023 |
| | | | | |
| Total Gross Margin | $40,159 | $39,250 | $165,050 | $149,729 |

| Volumes Sold (in Dth) | Three Months Ended Sept. 30, 2013 | 2012 | Nine Months Ended Sept. 30, 2013 | 2012 |
|---|---|---|---|---|
| Residential: | | | | |
| Colorado | 471,618 | 372,722 | 4,661,845 | 3,773,819 |
| Nebraska | 646,900 | 681,361 | 8,441,465 | 6,032,705 |
| Iowa | 521,223 | 479,912 | 7,544,375 | 5,486,267 |
| Kansas | 463,083 | 422,708 | 4,723,982 | 3,581,184 |
| Total Residential | 2,102,824 | 1,956,703 | 25,371,667 | 18,873,975 |
| | | | | |
| Commercial: | | | | |
| Colorado | 167,060 | 98,453 | 999,653 | 804,701 |
| Nebraska | 231,394 | 315,832 | 3,267,020 | 2,606,223 |
| Iowa | 552,814 | 527,923 | 4,523,365 | 3,424,736 |
| Kansas | 224,078 | 219,870 | 1,976,165 | 1,439,351 |
| Total Commercial | 1,175,346 | 1,162,078 | 10,766,203 | 8,275,011 |
| | | | | |
| Industrial: | | | | |
| Colorado | 237,848 | 265,451 | 374,709 | 416,020 |
| Nebraska | 44,184 | 69,229 | 88,449 | 134,931 |
| Iowa | 87,726 | 74,535 | 359,822 | 297,494 |
| Kansas | 1,742,551 | 1,912,296 | 3,154,217 | 3,381,657 |
| Total Industrial | 2,112,309 | 2,321,511 | 3,977,197 | 4,230,102 |
| | | | | |
| Total Volumes Sold | 5,390,479 | 5,440,292 | 40,115,067 | 31,379,088 |
| | | | | |
| Volumes Transported: | | | | |
| Colorado | 81,309 | 98,893 | 710,351 | 607,469 |
| Nebraska | 6,099,764 | 6,453,607 | 20,822,085 | 20,042,972 |
| Iowa | 4,422,788 | 4,038,804 | 14,892,528 | 13,718,759 |
| Kansas | 3,601,940 | 3,993,675 | 10,990,576 | 11,640,182 |
| Total Volumes Transported | 14,205,801 | 14,584,979 | 47,415,540 | 46,009,382 |
| | | | | |
| Wholesale: | | | | |
| Kansas | 12,359 | 8,427 | 86,568 | 40,380 |
| Total Other Volumes | 12,359 | 8,427 | 86,568 | 40,380 |
| | | | | |
| Total Volumes and Transportation Sold | 19,608,639 | 20,033,698 | 87,617,175 | 77,428,850 |

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

| | Three Months Ended Sept. 30, | | | |
|---|---|---|---|---|
| | 2013 | | 2012 | |
| Heating Degree Days: | Actual | Variance From 30-Year Average | Actual | Variance From 30-Year Average |
| Colorado | 83 | (54)% | 116 | (39)% |
| Nebraska | 31 | (68)% | 110 | 12% |
| Iowa | 138 | (1)% | 216 | 21% |
| Kansas [(a)] | 16 | (71)% | 42 | (35)% |
| Combined [(b)] | 79 | (38)% | 150 | 5% |

| | Nine Months Ended Sept. 30, | | | |
|---|---|---|---|---|
| | 2013 | | 2012 | |
| Heating Degree Days: | Actual | Variance From 30-Year Average | Actual | Variance From 30-Year Average |
| Colorado | 3,927 | 1% | 3,018 | (23)% |
| Nebraska | 3,929 | 6% | 2,880 | (22)% |
| Iowa | 4,754 | 13% | 3,629 | (19)% |
| Kansas [(a)] | 3,202 | 8% | 2,373 | (21)% |
| Combined [(b)] | 4,227 | 8% | 3,176 | (21)% |

(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism.

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Results of Operations for the Gas Utilities for the Three Months Ended Sept. 30, 2013 Compared to the Three Months Ended Sept. 30, 2012: Loss from continuing operations for the Gas Utilities was $1.5 million for the three months ended Sept. 30, 2013, compared to Income from continuing operations of $0.0 million for the three months ended Sept. 30, 2012, as a result of:

Gross margin increased primarily due to higher residential and commercial and transport volumes and higher weather normalized use per customer partially offset by lower industrial volumes.

Operations and maintenance increased primarily due to an increase in employee compensation and benefit costs and uncollectible accounts due to increased revenue.

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

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

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

Income tax benefit (expense): Each period presented produced a pre-tax loss that resulted in an income tax benefit. The income tax benefit recorded in 2012 was favorably impacted as a result of a true-up adjustment. No comparable adjustment was made in 2013.

Results of Operations for the Gas Utilities for the Nine Months Ended Sept. 30, 2013 Compared to the Nine Months Ended Sept. 30, 2012: Income from continuing operations for the Gas Utilities was $20.2 million for the nine months ended Sept. 30, 2013, compared to Income from continuing operations of $16.4 million for the nine months ended Sept. 30, 2012, as a result of:

Gross margin increased primarily due to higher residential consumption and transport volumes driven by 33 percent higher heating degree days compared to the same period in the prior year. Heating degree days were 8 percent higher than normal for the period.

Operations and maintenance increased primarily due to an increase in employee compensation and benefit costs and uncollectible accounts due to increased revenue.

Depreciation and amortization increased due to a higher asset base.

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

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

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

Regulatory Matters — Utilities Group

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

| | Type of Service | Date Requested | Effective Date | Revenue Amount Requested | Revenue Amount Approved |
|---|---|---|---|---|---|
| Iowa Gas [(a)] | Gas | 12/2012 | 6/2013 | $0.9 | $0.2 |
| Black Hills Power [(b)] | Electric | 12/2012 | 4/2013 | $13.7 | $8.8 |
| Black Hills Power [(c)] | Electric | 12/2012 | 4/2013 | $9.2 | $7.7 |

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

(b) On Dec. 17, 2012, Black Hills Power filed a request with the SDPUC seeking a 9.94 percent, or $13.7 million, increase in annual electric revenue, and interim rates were implemented on June 16, 2013. On Sept. 17, 2013, the SDPUC approved a settlement agreement resulting in a global settlement and an annual rate increase of $8.8 million, or 6.4 percent, effective June 16, 2013. Customer refunds will begin Nov. 1, 2013.

(c) On Sept. 17, 2013, the SDPUC approved a construction financing rider in lieu of traditional AFUDC, effective date of April 1, 2013, for the South Dakota portion of costs for Cheyenne Prairie. The rider allows Black Hills Power to earn and collect a rate of return during the construction period on its approximately 40 percent share of the total project cost that relates to South Dakota customers.

Non-regulated Energy Group

We report three segments within our Non-regulated Energy Group: Power Generation, Coal Mining and Oil and Gas.

Power Generation

| | Three Months Ended Sept. 30, | | | Nine Months Ended Sept. 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | 2013 | 2012 | Variance |
| | (in thousands) | | | | | |
| Revenue | $21,968 | $20,951 | $1,017 | $62,453 | $59,312 | $3,141 |
| | | | | | | |
| Operations and maintenance | 6,336 | 7,788 | (1,452) | 22,288 | 22,486 | (198) |
| Depreciation and amortization | 1,303 | 1,165 | 138 | 3,842 | 3,395 | 447 |
| Total operating expense | 7,639 | 8,953 | (1,314) | 26,130 | 25,881 | 249 |
| | | | | | | |
| Operating income | 14,329 | 11,998 | 2,331 | 36,323 | 33,431 | 2,892 |
| | | | | | | |
| Interest expense, net | (2,846) | (3,085) | 239 | (8,226) | (11,800) | 3,574 |
| Other (expense) income, net | 14 | (4) | 18 | 11 | 10 | 1 |
| Income tax (expense) benefit | (4,790) | (3,781) | (1,009) | (10,726) | (5,673) | (5,053) |
| | | | | | | |
| Income (loss) from continuing operations | $6,707 | $5,128 | $1,579 | $17,382 | $15,968 | $1,414 |

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

| | Three Months Ended Sept. 30, | | | | Nine Months Ended Sept. 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2013 | | 2012 | | 2013 | | 2012 | |
| Contracted power plant fleet availability: | | | | | | | | |
| Coal-fired plant | 100.0 | % | 99.4 | % | 98.0 | % | 99.5 | % |
| Natural gas-fired plants | 99.2 | % | 99.4 | % | 99.0 | % | 99.3 | % |
| Total availability | 99.4 | % | 99.4 | % | 98.8 | % | 99.4 | % |

Results of Operations for Power Generation for the Three Months Ended Sept. 30, 2013 Compared to the Three Months Ended Sept. 30, 2012: Income from continuing operations for the Power Generation segment was $6.7 million for the three months ended Sept. 30, 2013, compared to Income from continuing operations of $5.1 million for the same period in 2012 as a result of:

Revenue increased primarily due to an increase in off-system sales from five megawatts of capacity at Wygen I not under contract, and an increase in megawatt hours delivered at a higher price.

Operations and maintenance decreased primarily due to decreases in transmission expense and property taxes, partially offset by increased costs as a result of additional megawatt hours generated.

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

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

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

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

Results of Operations for Power Generation for the Nine Months Ended Sept. 30, 2013 Compared to the Nine Months Ended Sept. 30, 2012: Income from continuing operations for the Power Generation segment was $17.4 million for the nine months ended Sept. 30, 2013, compared to Income from continuing operations of $16.0 million for the same period in 2012 as a result of:

Revenue increased primarily due to an increase in megawatt hours delivered at a higher price, an increase in off-system sales from five megawatts of capacity not under contract at Wygen I.

Operations and maintenance was comparable to the same period in the prior year reflecting a decrease in property taxes partially offset by increased costs as a result of additional megawatt hours generated.

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

Interest expense, net decreased primarily due to lower debt balances.

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

Income tax (expense) benefit: The effective tax rate in the 2012 period was impacted by a favorable state tax true-up including certain tax credits pertaining to qualified plant expenditures related to capital investment and research and development.

Coal Mining

| | Three Months Ended Sept. 30, | | | Nine Months Ended Sept. 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | 2013 | 2012 | Variance |
| | (in thousands) | | | | | |
| Revenue | $15,317 | $14,675 | $642 | $43,218 | $42,791 | $427 |
| Operations and maintenance | 10,163 | 10,780 | (617) | 29,565 | 32,141 | (2,576) |
| Depreciation, depletion and amortization | 2,914 | 2,922 | (8) | 8,743 | 9,573 | (830) |
| Total operating expenses | 13,077 | 13,702 | (625) | 38,308 | 41,714 | (3,406) |
| Operating income (loss) | 2,240 | 973 | 1,267 | 4,910 | 1,077 | 3,833 |
| Interest (expense) income, net | (172) | 1 | (173) | (482) | 1,159 | (1,641) |
| Other income, net | 550 | 525 | 25 | 1,744 | 2,052 | (308) |
| Income tax benefit (expense) | (476) | 191 | (667) | (992) | (364) | (628) |
| Income (loss) from continuing operations | $2,142 | $1,690 | $452 | $5,180 | $3,924 | $1,256 |

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Tons of coal sold | 1,133 | 1,105 | 3,265 | 3,191 |
| Cubic yards of overburden moved | 685 | 1,827 | 2,674 | 6,749 |

Results of Operations for Coal Mining for the Three Months Ended Sept. 30, 2013 Compared to the Three Months Ended Sept. 30, 2012: Income from continuing operations for the Coal Mining segment was $2.1 million for the three months ended Sept. 30, 2013, compared to Income from continuing operations of $1.7 million for the same period in 2012 as a result of:

Revenue increased primarily due to increased pricing and a 3 percent increase in tons sold.

Operations and maintenance decreased primarily due to mining in areas with lower overburden, decreased fuel costs and reduced labor and benefits, partially offset by additional costs associated with a weather related coal conveyor failure.

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

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

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

Income tax benefit (expense): The effective tax rate for 2012 was positively impacted by a favorable true-up adjustment that was primarily driven by an increased percentage depletion deduction reported on the 2011 tax return.

Results of Operations for Coal Mining for the Nine Months Ended Sept. 30, 2013 Compared to the Nine Months Ended Sept. 30, 2012: Income from continuing operations for the Coal Mining segment was $5.2 million for the nine months ended Sept. 30, 2013, compared to Income from continuing operations of $3.9 million for the same period in 2012 as a result of:

Revenue was comparable to the same period in the prior year, reflecting a 1 percent decrease in average price per ton partially offset by a 2 percent increase in tons sold as a result of customer outages that occurred in the prior year period. Approximately 50 percent of our coal production is sold under contracts that include price adjustments based on actual mining costs. Our mining costs have trended down due to lower operating costs, thereby decreasing our price per ton for these customers. Most of our remaining production is sold under contracts where the sales price escalates periodically based on published indices.

Operations and maintenance decreased primarily due to mining in areas with lower overburden, decreased fuel costs and reduced labor and benefits, partially offset by additional costs associated with a weather related coal conveyor failure.

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

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

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

Income tax benefit (expense): The effective tax rate for 2012 was positively impacted by a favorable true-up adjustment that was primarily driven by an increased percentage depletion deduction reported on the 2011 tax return.

Oil and Gas

| | Three Months Ended Sept. 30, | | | Nine Months Ended Sept. 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | 2013 | 2012 | Variance |
| | (in thousands) | | | | | |
| Revenue | $14,426 | $24,728 | $(10,302) | $41,584 | $66,994 | $(25,410) |
| | | | | | | |
| Operations and maintenance | 10,662 | 12,118 | (1,456) | 30,912 | 33,290 | (2,378) |
| Gain on sale of operating assets | — | (27,285) | 27,285 | — | (27,285) | 27,285 |
| Depreciation, depletion and amortization | 6,157 | 12,457 | (6,300) | 16,738 | 34,813 | (18,075) |
| Impairment of long-lived assets | — | — | — | — | 26,868 | (26,868) |
| Total operating expenses | 16,819 | (2,710) | 19,529 | 47,650 | 67,686 | (20,036) |
| | | | | | | |
| Operating income (loss) | (2,393) | 27,438 | (29,831) | (6,066) | (692) | (5,374) |
| | | | | | | |
| Interest income (expense), net | (339) | (1,112) | 773 | (314) | (3,882) | 3,568 |
| Other income (expense), net | 58 | 77 | (19) | 62 | 193 | (131) |
| Income tax benefit (expense) | 992 | (9,014) | 10,006 | 2,619 | 2,162 | 457 |
| | | | | | | |
| Income (loss) from continuing operations | $(1,682) | $17,389 | $(19,071) | $(3,699) | $(2,219) | $(1,480) |

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

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Production: | | | | |
| Bbls of oil sold | 84,260 | 184,423 | 246,367 | 485,262 |
| Mcf of natural gas sold | 1,765,622 | 2,278,801 | 5,282,961 | 7,119,087 |
| Gallons of NGL sold | 988,682 | 1,099,198 | 2,830,216 | 2,751,409 |
| Mcf equivalent sales | 2,412,422 | 3,542,367 | 7,165,479 | 10,423,717 |

| | Three Months Ended Sept. 30, | | Nine Months Ended Sept. 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Average price received: [(a)] | | | | |
| Oil/Bbl | $94.32 | $88.69 | $92.60 | $81.65 |
| Gas/Mcf | $2.82 | $3.07 | $2.69 | $3.27 |
| NGL/gallon | $0.71 | $0.65 | $0.79 | $0.77 |
| | | | | |
| Depletion expense/Mcfe | $2.16 | $3.26 | $1.92 | $3.07 |

__________

(a) Net of hedge settlement gains and losses.

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

| | Three Months Ended Sept. 30, 2013 | | | | Three Months Ended Sept. 30, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| Producing Basin | LOE | Gathering, Compression and Processing | Production Taxes | Total | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | $1.39 | $0.42 | $0.44 | $2.25 | $1.42 | $0.33 | $0.46 | $2.21 |
| Piceance | 0.70 | 0.47 | 0.50 | 1.67 | 0.13 | 0.35 | 0.14 | 0.62 |
| Powder River | 1.53 | — | 1.15 | 2.68 | 1.00 | — | 1.11 | 2.11 |
| Williston | 1.19 | — | 1.24 | 2.43 | 0.70 | — | 1.48 | 2.18 |
| All other properties | 1.08 | — | 0.69 | 1.77 | 1.48 | — | 0.25 | 1.73 |
| Total weighted average | $1.26 | $0.25 | $0.70 | $2.21 | $0.99 | $0.17 | $0.74 | $1.90 |

| | Nine Months Ended Sept. 30, 2013 | | | | Nine Months Ended Sept. 30, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| Producing Basin | LOE | Gathering, Compression and Processing | Production Taxes | Total | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | $1.36 | $0.39 | $0.46 | $2.21 | $1.14 | $0.28 | $0.34 | $1.76 |
| Piceance | 0.72 | 0.54 | 0.36 | 1.62 | 0.20 | 0.39 | 0.13 | 0.72 |
| Powder River | 1.59 | — | 1.21 | 2.80 | 1.33 | — | 1.17 | 2.50 |
| Williston | 1.03 | — | 1.31 | 2.34 | 0.65 | — | 1.35 | 2.00 |
| All other properties | 0.81 | — | 0.18 | 0.99 | 1.58 | — | 0.17 | 1.75 |
| Total weighted average | $1.22 | $— | $0.63 | $1.85 | $0.96 | $0.17 | $0.63 | $1.76 |

Results of Operations for Oil and Gas for the Three Months Ended Sept. 30, 2013 Compared to the Three Months Ended Sept. 30, 2012: Loss from continuing operations for the Oil and Gas segment was $1.7 million for the three months ended Sept. 30, 2013, compared to Income from continuing operations of $17.4 million for the same period in 2012 as a result of:

Revenue decreased primarily due to a 32 percent decrease in volumes sold as a result of the sale of our Williston Basin assets in 2012, and an 8 percent decrease in the average price received for natural gas sold, partially offset by a 6 percent increase in the average price received for crude oil sold.

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

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

Gain on sale of operating assets was related to the sale of our Williston Basin assets in 2012. We follow the full-cost method of accounting for oil and gas activities, which typically does not allow for recognition of a gain or loss on sale unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. The sale of the Williston Basin assets significantly altered the relationship and accordingly we recorded a gain of $27.3 million with the remainder of the proceeds recorded as a reduction in the full cost pool. The remainder of the sales amount, not recognized as gain, reduces the full-cost pool and should significantly decrease the future depreciation, depletion, and amortization rate.

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

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

Income tax (expense) benefit: In 2013, a pre-tax net loss was generated that resulted in an income tax benefit. The effective tax rate in the 2013 period reflects a favorable true-up adjustment that increased the tax benefit. For the 2012 period, pre-tax net income was generated as a result of the gain on sale of our Williston Basin assets. The effective tax rate is a reflection of such gain.

Results of Operations for Oil and Gas for the Nine Months Ended Sept. 30, 2013 Compared to the Nine Months Ended Sept. 30, 2012: Loss from continuing operations for the Oil and Gas segment was $3.7 million for the nine months ended Sept. 30, 2013, compared to Loss from continuing operations of $2.2 million for the same period in 2012 as a result of:

Revenue decreased primarily due to a 31 percent decrease in volumes sold as a result of the sale of our Williston Basin asset in 2012, a natural production decline in our Mancos formation wells and an 18 percent decrease in the average price received for natural gas sold, partially offset by a 13 percent increase in the average price received for crude oil sold.

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

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

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

Gain on sale of operating assets was related to the sale of our Williston Basin assets in 2012. We follow the full-cost method of accounting for oil and gas activities, which typically does not allow for recognition of a gain or loss on sale unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. The sale of the Williston Basin assets significantly altered the relationship and accordingly we recorded a gain of $27.3 million with the remainder of the proceeds recorded as a reduction in the full cost pool. The remainder of the sales amount, not recognized as gain, reduces the full-cost pool and should significantly decrease the future depreciation, depletion, and amortization rate.

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

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

Income tax (expense) benefit: Each period presented produced a pre-tax net loss that resulted in an income tax benefit. The effective tax rate in the 2013 period reflects a lesser tax benefit attributable to percentage depletion.

Corporate Activity

Results of Operations for Corporate activities for the Three Months Ended Sept. 30, 2013 Compared to the Three Months Ended Sept. 30, 2012: Income from continuing operations for Corporate was $2.3 million for the three months ended Sept. 30, 2013, compared to Loss from continuing operations of $4.2 million for the three months ended Sept. 30, 2012 as a result of:

- Market interest rate changes creating unrealized, non-cash mark-to-market gains of $3.1 million on certain interest rate swaps for the three months ended Sept. 30, 2013 as compared to a gain of $0.6 million on these same interest rate swaps for the three months ended Sept. 30, 2012.
- The income from continuing operations for the three months ended Sept. 30, 2013, included lower interest expense as compared to the three months ended Sept. 30, 2012, as a result of an allocation of debt-related costs included in Corporate activities for the three months ended Sept. 30, 2012, now allocated among our segments for the three months Sept. 30, 2013, in order to better align the capital structure among the segments.
- The losses for the quarter ended Sept. 30, 2012, included an incentive compensation accrual recorded as a result of the sale of the Williston Basin asset.

Results of Operations for Corporate activities for the Nine Months Ended Sept. 30, 2013 Compared to the Nine Months Ended Sept. 30, 2012: Income from continuing operations for Corporate was $19.7 million for the nine months ended Sept. 30, 2013, compared to Loss from continuing operations of $13.9 million for the nine months ended Sept. 30, 2012 as a result of:

- Market interest rate changes creating unrealized, non-cash mark-to-market gains of $29.4 million on certain interest rate swaps for the nine months ended Sept. 30, 2013 as compared to losses of $2.9 million for these same interest rate swaps for the nine months ended Sept. 30, 2012.
- The income from continuing operations for the nine months ended Sept. 30, 2013, included lower interest expense as compared to the nine months ended Sept. 30, 2012, as a result of an allocation of debt-related costs included in Corporate activities for the nine months ended Sept. 30, 2012, now allocated among our segments for the nine months ended Sept. 30, 2013, in order to better align the capital structure of the corporation among the segments.
- The losses for the nine months ended Sept. 30, 2012, include costs originally allocated to our Energy Marketing segment, which could not be reclassified to discontinued operations in accordance with GAAP, and were included in Corporate activities for the nine months ended Sept. 30, 2012.
- The losses for the nine months ended Sept. 30, 2012 included an incentive compensation accrual recorded as a result of the sale of the Williston Basin asset.

## Discontinued Operations

Results of Operations for Discontinued Operations for the Three and Nine Months Ended Sept. 30, 2013, Compared to the Three and Nine Months Ended Sept. 30, 2012:

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. We recorded a Loss from discontinued operations, net of tax, for the three and nine months ended Sept. 30, 2012, of $0.2 million and $6.8 million, respectively.

After the sale of Enserco and pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments, which we disputed. The buyer filed a petition in the Colorado District Court for the City and County of Denver, Colo., seeking an order compelling binding arbitration on all of the disputed claims. Following a hearing in July 2013, the court entered an order remanding all but one of the disputed adjustment claims to arbitration. We continue to dispute the validity of the adjustment claims within the arbitration process, which we expect will conclude before the end of 2013.

## Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2012 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting policies, see Part II, Item 7 of our 2012 Annual Report on Form 10-K.

## Liquidity and Capital Resources

### OVERVIEW

BHC and its subsidiaries require cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate borrowings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate.

The most significant items impacting cash are our capital expenditures, the purchase of natural gas for our Utilities Group and our Power Generation segment, and the payment of dividends to our shareholders. We could experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices.

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

Significant Factors Affecting Liquidity

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

Cash Flow Activities

The following table summarizes our cash flows for the nine months ended Sept. 30, 2013 and 2012, (in thousands):

| Cash provided by (used in): | 2013 | 2012 | Increase (Decrease) |
|---|---|---|---|
| Operating activities | $251,766 | $269,667 | $(17,901) |
| Investing activities | $(236,639) | $98,306 | $(334,945) |
| Financing activities | $(16,952) | $(179,549) | $162,597 |

Nine Months Ended Sept. 30, 2013 Compared to Nine Months Ended Sept. 30, 2012

Operating Activities

Net cash provided by operating activities was $17.9 million lower for the nine months ended Sept. 30, 2013, than for the same period in 2012 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $30.5 million higher for the nine months ended Sept. 30, 2013 than for the same period in the prior year.
- Net outflows from operating assets and liabilities were $7.5 million for the nine months ended Sept. 30, 2013, compared to net cash inflows of $37.3 million in the same period in the prior year. Changes are normal working capital changes influenced by increase in natural gas prices for the Utilities Group, expiration of the PPA with PSCo, and receipt of approximately $8 million from a government grant relating to the Busch Ranch wind project during 2013.
- Cash contributions to the defined benefit pension plan of $12.5 million were made in the nine months ended Sept. 30, 2013 compared to $25.0 million in the same period in the prior year.
- A $21.2 million decrease in net cash inflows from discontinued operations in 2013 compared to the same period in the prior year.

Investing Activities

Net cash used in investing activities was $236.6 million for the nine months ended Sept. 30, 2013, compared to net cash provided by investing activities of $98.3 million for the same period in 2012 for a variance of $334.9 million. The variance was driven by:

- Cash proceeds received from assets sold during the nine months ended Sept. 30, 2012, including the sale of our Williston Basin assets, the partial sale of the Busch Ranch wind project, and the sale of Enserco.

- Capital expenditures of approximately $96 million for the nine months ended Sept. 30, 2013, related to the construction of Cheyenne Prairie at our Electric Utilities segment compared to $3.6 million for the nine months ended Sept. 30, 2012, offset by a decrease in capital spending at Oil and Gas.

- The 2012 period included approximately $22 million note receivable relating to our oil and gas properties.

Financing Activities

Net cash used in financing activities for the nine months ended Sept. 30, 2013, was $17.0 million, compared to net cash used in financing activities for the same period in 2012 of $179.5 million for a variance of $162.6 million. The variance was driven by:

- Proceeds from the 2012 asset sales were used to pay down short-term borrowings on the Revolving Credit Facility.

- Increased borrowings in 2013 to finance our construction of Cheyenne Prairie offset by decreased borrowings for capital expenditures in our Oil and Gas segment and the completion of Busch Ranch wind project in 2012.

- The 2013 repayment of our $150 million and $100 million term loans was offset by the issuance of a $275 million long-term term loan.

Dividends

Dividends paid on our common stock totaled $50.7 million for the nine months ended Sept. 30, 2013, or $1.14 per share. On Oct. 29, 2013, our board of directors declared a quarterly dividend of $0.38 per share payable Dec. 1, 2013, which is equivalent to an annual dividend rate of $1.52 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Debt

Financing Transactions and Short-Term Liquidity

Our principal sources to meet day-to-day operating cash requirements are cash from operations and our corporate Revolving Credit Facility.

Revolving Credit Facility

We have a $500 million corporate Revolving Credit Facility that matures on Feb. 1, 2017, and has an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings are available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon the lowest credit ratings of S&P and Moody's that apply to our debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50 percent, 1.50 percent and 1.50 percent, respectively, during the three and nine months ended Sept. 30, 2013. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.25 percent based on our credit rating.

On Sept. 25, 2013, Moody's upgraded our credit rating, which triggered improved interest costs on our Revolving Credit Facility, which are based on the lowest credit ratings of S&P and Moody's.  On Oct. 2, 2013, the margins for our base rate borrowings, Eurodollar borrowings and letters of credit changed to 0.375 percent, 1.375 percent and 1.375 percent, respectively. The commitment fee charged on the unused portion of the Revolving Credit Facility also changed to 0.20 percent.

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

| Credit Facility | Expiration | Current Capacity | Borrowings at Sept. 30, 2013 | Letters of Credit at Sept. 30, 2013 | Available Capacity at Sept. 30, 2013 |
|---|---|---|---|---|---|
| Revolving Credit Facility | Feb. 1, 2017 | $500 | $138.3 | $53.1 | $308.6 |

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a certain minimum net worth and recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is the ratio of our recourse debt, letters of credit and certain guarantees issued, divided by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of Sept. 30, 2013.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Term Loans

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

Future Financing Plans

We are considering the following financing activities:

- Refinancing our $250 million, 9 percent senior unsecured notes that mature in May 2014;
- Partial or full settlement of our de-designated interest rate swaps; and
- Long-term financing options for the Cheyenne Prairie project.

Hedges and Derivatives

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations.

We have interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the Condensed Consolidated Statements of Income (Loss). For the three and nine months ended Sept. 30, 2013, respectively, we recorded $3.1 million and $29.4 million pre-tax unrealized non-cash mark-to-market gains on the swaps. The mark-to-market value on these swaps was a liability of $58.8 million at Sept. 30, 2013. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves divided by the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of approximately 5.25 years and 15.25 years and have early termination dates ranging from Dec. 15, 2013 to Dec. 31, 2013. We anticipate extending these agreements upon their early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended we will cash settle these swaps for an amount equal to their fair values on the early termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of approximately 3.25 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 $18.4 million at Sept. 30, 2013.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40 percent of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of Sept. 30, 2013, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $148.6 million.
Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenant from our Revolving Credit Facility is a recourse leverage ratio not to exceed 0.65 to 1.00. Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of Sept. 30, 2013, we were in compliance with these covenants.

As required by a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings, the parent of Black Hills Electric Generation, which is the parent of Black Hills Wyoming, has restricted shareholders' equity of at least $100 million. In addition, Black Hills Wyoming holds $6.8 million of restricted cash associated with the project financing requirements.

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

Credit Ratings

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

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

| Rating Agency | Senior Unsecured Rating | Outlook |
|---|---|---|
| S&P [(a)] | BBB | Stable |
| Moody's[(b)] | Baa2 | Positive |
| Fitch [(c)] | BBB | Positive |

(a) On July 24, 2013, S&P upgraded the BHC credit rating to BBB with a Stable outlook.
(b) On Sept. 25, 2013, Moody's upgraded the BHC credit rating to Baa2 with a Positive outlook.
(c) On May 10, 2013, Fitch upgraded the BHC credit rating to BBB with a Positive outlook.

The following table represents the credit ratings of Black Hills Power's Senior Secured Mortgage Bonds at Sept. 30, 2013:

| Rating Agency | Senior Secured Rating |
|---|---|
| S&P * | A- |
| Moody's ** | A2 |
| Fitch | A- |

* On July 24, 2013, S&P upgraded the BHP credit rating to A-.
** On Sept. 25, 2013, Moody's upgraded the BHP credit rating to A2 from A3.

Capital Requirements

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

| | Expenditures for the Nine Months Ended Sept. 30, 2013 | Total 2013 Planned Expenditures | Total 2014 Planned Expenditures | Total 2015 Planned Expenditures |
|---|---|---|---|---|
| Utilities: | | | | |
| Electric Utilities | $157,436 | $245,100 | $250,700 | $189,300 |
| Gas Utilities | 39,730 | 65,100 | 60,400 | 52,600 |
| Non-regulated Energy: | | | | |
| Power Generation | 3,755 | 14,900 | 2,500 | 5,200 |
| Coal Mining | 4,739 | 7,100 | 6,600 | 6,200 |
| Oil and Gas | 37,435 | 98,300 | 117,800 | 122,700 |
| Corporate | 8,416 | 12,700 | 8,800 | 5,900 |
| | $251,511 | $443,200 | $446,800 | $381,900 |

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

Contractual Obligations

Except as noted below, there have been no significant changes in the contractual obligations from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2012 Annual Report on Form 10-K.

Purchase Power and Power Sales Agreements

The following purchase power and power sales agreements were renewed:

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

Construction Commitments

Construction of Cheyenne Prairie, a 132 megawatt natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by Sept. 30, 2014. As of Sept. 30, 2013, contracts for equipment purchases and for construction were 94 percent and 67 percent committed, respectively.

Purchase and Sale Agreement

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

Sale of Enserco Energy Inc.

After the sale of Enserco, our Energy Marketing segment, on Feb. 29, 2012, and pursuant to the provisions of the Stock Purchase Agreement, the buyer requested purchase price adjustments, which we disputed. The buyer filed a petition in the Colorado District Court for the City and County of Denver, Colo., seeking an order compelling binding arbitration on all of the disputed claims. Following a hearing in July 2013, the court entered an order remanding all but one of the disputed adjustment claims to arbitration. We continue to dispute the validity of the adjustment claims within the arbitration process, which we expect will conclude before the end of 2013.

Guarantees

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

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

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

New Accounting Pronouncements

Other than the pronouncements reported in our 2012 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

FORWARD-LOOKING INFORMATION

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

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement was made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2012 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2012 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

| | Sept. 30, 2013 | Dec. 31, 2012 | Sept. 30, 2012 |
|---|---|---|---|
| Net derivative (liabilities) assets | $(8,396) | $(8,533) | $(7,253) |
| Cash collateral offset in Derivatives | 8,396 | 8,576 | 15,740 |
| Cash Collateral included in Other current assets | 3,333 | 4,354 | — |
| Net receivable (liability) position | $3,333 | $4,397 | $8,487 |

Oil and Gas Activities

We have entered into agreements to hedge a portion of our estimated 2013, 2014 and 2015 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at Sept. 30, 2013, were as follows:

Natural Gas

| | For the Three Months Ended | | | | |
|---|---|---|---|---|---|
| | March 31, | June 30, | Sept. 30, | Dec. 31, | Total Year |
| 2013 | | | | | |
| Swaps - MMBtu | — | — | — | 1,154,000 | 1,154,000 |
| Weighted Average Price per MMBtu | $— | $— | $— | $3.50 | $3.50 |
| 2014 | | | | | |
| Swaps - MMBtu | 1,040,000 | 997,500 | 1,005,000 | 1,005,000 | 4,047,500 |
| Weighted Average Price per MMBtu | $3.74 | $3.80 | $3.99 | $3.99 | $3.88 |
| 2015 | | | | | |
| Swaps - MMBtu | 900,000 | 862,500 | 500,000 | 455,000 | 2,717,500 |
| Weighted Average Price per MMBtu | $4.24 | $3.99 | $4.08 | $4.16 | $4.12 |

Crude Oil

| | For the Three Months Ended | | | | |
|---|---|---|---|---|---|
| | March 31, | June 30, | Sept. 30, | Dec. 31, | Total Year |
| 2013 | | | | | |
| Swaps - Bbls | — | — | — | 24,000 | 24,000 |
| Weighted Average Price per Bbl | $— | $— | $— | $101.47 | $101.47 |
| | | | | | |
| Puts - Bbls | — | — | — | 36,000 | 36,000 |
| Weighted Average Price per Bbl | $— | $— | $— | $80.63 | $80.63 |
| | | | | | |
| Calls - Bbls | — | — | — | 36,000 | 36,000 |
| Weighted Average Price per Bbl | $— | $— | $— | $97.25 | $97.25 |
| | | | | | |
| 2014 | | | | | |
| Swaps - Bbls | 60,000 | 60,000 | 57,000 | 57,000 | 234,000 |
| Weighted Average Price per Bbl | $95.48 | $90.65 | $90.55 | $90.66 | $91.86 |
| | | | | | |
| 2015 | | | | | |
| Swaps - Bbls | 55,500 | 51,000 | 39,000 | 24,000 | 169,500 |
| Weighted Average Price per Bbl | $89.98 | $87.84 | $87.73 | $87.68 | $88.49 |

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. Further details of the swap agreements are set forth in Note 3 of the Notes to Consolidated Financial Statements in our 2012 Annual Report on Form 10-K and in Note 10 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

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

| | Sept. 30, 2013 | | Dec. 31, 2012 | | Sept. 30, 2012 | |
|---|---|---|---|---|---|---|
| | Designated Interest Rate Swaps | De-designated Interest Rate Swaps* | Designated Interest Rate Swaps | De-designated Interest Rate Swaps* | Designated Interest Rate Swaps | De-designated Interest Rate Swaps* |
| Notional | $150,000 | $ 250,000 | $150,000 | $ 250,000 | $150,000 | $ 250,000 |
| Weighted average fixed interest rate | 5.04 % | 5.67 % | 5.04 % | 5.67 % | 5.04 % | 5.67 % |
| Maximum terms in years | 3.25 | 0.25 | 4.00 | 1.00 | 4.25 | 1.25 |
| Derivative liabilities, current | $7,039 | $ 58,755 | $7,039 | $ 88,148 | $7,028 | $ 77,914 |
| Derivative liabilities, non-current | $11,388 | $ — | $16,941 | $ — | $18,660 | $ 17,668 |
| Cash collateral receivable (payable) included in derivatives | $— | $ 5,960 | $— | $ 5,960 | $— | $ 3,310 |

* Maximum terms in years for our de-designated interest rate swaps reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. If extended annually, de-designated swaps totaling $100.0 million terminate in approximately 5.25 years and de-designated swaps totaling $150.0 million terminate in approximately 15.25 years.

Based on Sept. 30, 2013 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $7.0 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and actual realized gains or losses will change during future periods as market interest rates change.

## ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of Sept. 30, 2013. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

During the quarter ended Sept. 30, 2013, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2012 Annual Report on Form 10-K and Note 13 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 13 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes, except as noted below, to the risk factors previously disclosed in Item 1A of Part I in our 2012 Annual Report on Form 10-K.

OPERATING RISKS

Operating results can be adversely affected by variations from normal weather conditions.

Our utility businesses are seasonal businesses, and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating. Because natural gas is primarily used for residential and commercial heating, the demand for this product depends heavily upon winter weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Unusually mild summers and winters therefore could have an adverse effect on our financial condition and results of operations.

Our businesses are located in areas that could be subject to seasonal natural disasters such as severe snow and ice storms, flooding and wildfires. These factors could result in interruption of our business, damage to our property such as power lines and substations, and repair and clean-up costs associated with these storms. We may not be able to recover the costs incurred in restoring transmission and distribution property following these natural disasters through a change in our regulated rates thereby resulting in a negative impact on our results of operations, financial condition and cash flows.

Our coal mining operations are subject to operating risks that are beyond our control which could affect our profitability and production levels. Our surface mining operations could be disrupted or materially affected due to adverse weather or natural disasters such as heavy snow, strong winds, rain or flooding. Additionally, weather patterns can also affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage, and therefore, increased generating requirements and use of coal. Conversely, mild temperatures could result in lower electrical demand.

Weather conditions can also limit or temporarily halt our drilling, completion and producing activities and other crude oil and natural gas operations. Primarily in the winter and spring, our operations can be curtailed because of cold, snow, and wet conditions. Severe weather could further curtail these operations, including drilling and completing of new wells or production from existing wells. In addition, weather conditions and other events could temporarily impair our ability to transport our crude oil and natural gas production.

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POWER GENERATION

Our inability to successfully complete the sale of Black Hills Wyoming's CTII combustion turbine to the City of Gillette, Wyo. or to sell Black Hills Wyoming's ownership interest in the Wygen I facility to Cheyenne Light could adversely affect our Power Generation segment.
Black Hills Wyoming entered into an agreement to sell its 40 megawatt simple-cycle, gas-fired combustion turbine ("CTII") to the City of Gillette, Wyo. in August 2014 upon expiration of an existing power sales agreement under which Black Hills Wyoming sells the output of the CTII to our subsidiary Cheyenne Light. This sale is subject to FERC approval and certain other requirements included in the contract.

Black Hills Wyoming also has a power sales agreement with Cheyenne Light which expires in December 2022. This power sales agreement includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. If Cheyenne Light exercises its purchase option, the sale would be subject to Wyoming Public Service Commission and FERC approval.

Failure of Black Hills Wyoming to complete the sale of CTII to the City of Gillette or the sale of its ownership interest in the Wygen I facility to Cheyenne Light if Cheyenne Light exercises its purchase option, whether due to failure to obtain regulatory approval or otherwise, could adversely affect our results of operations, financial position and liquidity, particularly if we are unable to obtain power sales contracts at reasonable rates to fully utilize these assets subsequent to the expiration of the power sales contracts that are currently in effect.

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 |
|---|---|---|---|---|
| July 1, 2013 - July 31, 2013 | — | $— | — | — |
| Aug. 1, 2013 - Aug. 31, 2013 | 2,746 | $52.82 | — | — |
| Sept. 1, 2013 - Sept. 30, 2013 | — | $— | — | — |
| Total | 2,746 | $52.82 | — | — |

(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.

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ITEM 5. Other Information

On Jan. 1, 2013, we adopted ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities, which enhances disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position. This ASU was effective for annual and interim reporting periods beginning on or after Jan. 1, 2013 and is to be applied retrospectively for all comparative periods presented. The impact of retrospectively adjusting for the adoption of this ASU was immaterial to our historical consolidated financial statements.

The following presents the unaudited retrospective application of ASU 2011-11 by providing reconciliation between the gross assets and gross liabilities reflected on the Consolidated Balance Sheet and the potential effects of master netting arrangements on the fair value of our derivative contracts at Dec. 31, 2011.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheet was as follows (in thousands):

| | As of Dec. 31, 2011 | | |
|---|---|---|---|
| Derivative Assets | Gross Amounts of Derivative Assets | Gross Amounts Offset on Consolidated Balance Sheet | Net Amount of Total Derivative Assets on Consolidated Balance Sheet |
| Subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Utilities | $965 | $8,931 | $9,896 |
| Total derivative assets subject to a master netting agreement or similar arrangement | 965 | 8,931 | 9,896 |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Basis Swaps | 1,500 | — | 1,500 |
| Oil and Gas - Natural Gas Basis Swaps | 9,158 | — | 9,158 |
| Total derivative assets not subject to a master netting agreement or similar arrangement | 10,658 | — | 10,658 |
| Total derivative assets | $11,623 | $8,931 | $20,554 |

| Derivative Liabilities | As of Dec. 31, 2011<br>Gross Amounts of Derivative Liabilities | Gross Amounts Offset on Consolidated Balance Sheet | Net Amount of Total Derivative Liabilities on Consolidated Balance Sheet |
|---|---|---|---|
| Subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Utilities | $17,643 | $(10,487) | $7,156 |
| Total derivative liabilities subject to a master netting agreement or similar arrangement | 17,643 | (10,487) | 7,156 |
| Not subject to a master netting agreement or similar arrangement: | | | |
| Commodity derivative: | | | |
| Oil and Gas - Crude Options | 3,370 | — | 3,370 |
| Oil and Gas - Natural Gas Basis Swaps | 7 | — | 7 |
| Interest Rate Swaps | 122,867 | — | 122,867 |
| Total derivative liabilities not subject to a master netting agreement or similar arrangement | 126,244 | — | 126,244 |
| Total derivative liabilities | $143,887 | $(10,487) | $133,400 |

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

| Contract Type | | As of Dec. 31, 2011<br>Net Amount of Total Derivative Assets | Gross Amounts Not Offset on Consolidated Balance Sheet<br>Cash Collateral Received | Net Amount with Counterparty |
|---|---|---|---|---|
| Asset: | | | | |
| Oil and Gas | Counterparty A | $— | $— | $— |
| Oil and Gas | Counterparty B | 10,658 | — | 10,658 |
| Utilities | Counterparty A | 9,896 | — | 9,896 |
| | | $20,554 | $— | $20,554 |

| | | As of Dec. 31, 2011 | | |
|---|---|---|---|---|
| | | | Gross Amounts Not Offset on Consolidated Balance Sheet | |
| Contract Type | | Net Amount of Total Derivative Liabilities | Cash Collateral Posted | Net Amount with Counterparty |
| Liabilities | | | | |
| Oil and Gas | Counterparty A | $— | $— | $— |
| Oil and Gas | Counterparty B | 3,377 | — | 3,377 |
| Utilities | Counterparty A | 7,156 | — | 7,156 |
| Interest Rate Swap | Counterparty D | 5,140 | — | 5,140 |
| Interest Rate Swap | Counterparty E | 31,095 | — | 31,095 |
| Interest Rate Swap | Counterparty F | 13,880 | — | 13,880 |
| Interest Rate Swap | Counterparty G | 26,329 | — | 26,329 |
| Interest Rate Swap | Counterparty H | 23,203 | — | 23,203 |
| Interest Rate Swap | Counterparty I | 23,220 | — | 23,220 |
| | | $133,400 | $— | $133,400 |

ITEM 6. Exhibits

| Exhibit Number | Description |
|---|---|
| Exhibit 2.1* | Stock Purchase Agreement by and between Twin Eagle Resource Management, LLC and Black Hills Non-Regulated Holdings LLC for the purchase of capital stock of Enserco Energy Inc., dated January 18, 2012 (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2012). |
| Exhibit 2.2* | Purchase and Sale Agreement, dated as of August 23, 2012, by and among Black Hills Exploration and Production, Inc. and other sellers and QEP Energy Company, as Purchaser (excluding exhibits and certain schedules, which the Registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request) (filed as Exhibit 2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2012). |
| Exhibit 3.1* | Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004). |
| Exhibit 3.2* | Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010). |
| Exhibit 4.1* | Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to the Registrant's Form 8-K filed on July 15, 2010). |
| Exhibit 4.2* | Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| Exhibit 4.3* | Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000). |

| Exhibit Number | Description |
|---|---|
| Exhibit 31.1 | Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 31.2 | Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 32.1 | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 32.2 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002. |
| Exhibit 95 | Mine Safety and Health Administration Safety Data. |
| Exhibit 101 | Financial Statements for XBRL Format. |

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

SIGNATURES

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

BLACK HILLS CORPORATION

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

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

Dated: November 5, 2013

INDEX TO EXHIBITS

| Exhibit Number | Description |
|---|---|
| Exhibit 2.1* | Stock Purchase Agreement by and between Twin Eagle Resource Management, LLC and Black Hills Non-Regulated Holdings LLC for the purchase of capital stock of Enserco Energy Inc., dated January 18, 2012 (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2012). |
| Exhibit 2.2* | Purchase and Sale Agreement, dated as of August 23, 2012, by and among Black Hills Exploration and Production, Inc. and other sellers and QEP Energy Company, as Purchaser (excluding exhibits and certain schedules, which the Registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request) (filed as Exhibit 2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2012). |
| Exhibit 3.1* | Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004). |
| Exhibit 3.2* | Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010). |
| Exhibit 4.1* | Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to the Registrant's Form 8-K filed on July 15, 2010). |
| Exhibit 4.2* | Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| Exhibit 4.3* | Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000). |

| Exhibit Number | Description |
|---|---|
| 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. |
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