

BLACK HILLS CORP /SD/
Form 10-Q
November 04, 2011

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

Form 10-Q

- QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2011.
- OR
- 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
625 Ninth Street
Rapid City, South Dakota 57701

IRS Identification Number 46-0458824

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 No

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 No

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 Accelerated filer
Non-accelerated filer Smaller reporting company

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

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

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| Class | Outstanding at October 31, 2011 |
|--------------------------------|---------------------------------|
| Common stock, \$1.00 par value | 39,468,273 shares |

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GLOSSARY OF TERMS AND ABBREVIATIONS
AND ACCOUNTING STANDARDS

The following terms and abbreviations and accounting standards 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) |
| ASC | Accounting Standards Codification |
| ASC 220 | ASC 220, "Comprehensive Income" |
| ASC 350 | ASC 350, "Intangibles - Goodwill and Other" |
| ASC 820 | ASC 820, "Fair Value Measurements and Disclosures" |
| ASU | Accounting Standards Update |
| Bbl | Barrel |
| Bcf | Billion cubic feet |
| Bcfe | Billion cubic feet equivalent |
| BHC | Black Hills Corporation |
| BHCRPP | Black Hills Corporation Risk Policies and Procedures |
| BHEP | Black Hills Exploration and Production, Inc., representing our Oil and Gas segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings |
| Black Hills Electric Generation | Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings |
| Black Hills Energy | The name used to conduct the business activities of Black Hills Utility Holdings |
| Black Hills Non-regulated Holdings | Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company |
| Black Hills Power | Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company |
| Black Hills Service Company | Black Hills Service Company, a direct wholly-owned subsidiary of the Company |
| Black Hills Utility Holdings | Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company |
| Black Hills Wyoming | Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation |
| Btu | British thermal unit |
| CFTC | United States Commodities Futures Trading Commission |
| Cheyenne Light | Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company |
| Colorado Electric | Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings |
| Colorado Gas | Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings |
| Colorado IPP | Black Hills Colorado IPP, a direct wholly-owned subsidiary of Black Hills Electric Generation |
| CPCN | Certificate of Public Convenience and Necessity |
| CPUC | Colorado Public Utilities Commission |
| CT | Combustion Turbine |

| | |
|-----------------------------------|---|
| De-designated interest rate swaps | The \$250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008 |
| 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, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings |
| Equity Forward Agreement | Equity Forward Agreement with J.P. Morgan connected to a public offering of 4,413,519 shares of Black Hills Corporation common stock |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | Generally Accepted Accounting Principles of the United States |
| Global Settlement | Settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders |
| IFRS | International Financial Reporting Standards |
| Iowa Gas | Black Hills Iowa Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings |
| IPP | Independent Power Producer |
| IRS | Internal Revenue Service |
| 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 | One thousand standard cubic feet |
| Mcfe | One thousand standard cubic feet equivalent |
| MMBtu | One million British thermal units |
| MSHA | Mine Safety and Health Administration |
| MW | Megawatt |
| MWh | Megawatt-hour |
| Nebraska Gas | Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings |
| NPSC | Nebraska Public Service Commission |
| NYMEX | New York Mercantile Exchange |
| OCA | Office of Consumer Advocate |
| PGA | Purchase Gas Adjustment |
| PPA | Power Purchase Agreement |
| PPACA | Patient Protection and Affordability Care Act |
| PSCo | Public Service Company of Colorado |
| Revolving Credit Facility | Our \$500 million three-year revolving credit facility which commenced on April 15, 2010 and expires on April 14, 2013 |
| SDPUC | South Dakota Public Utilities Commission |
| SEC | United States Securities and Exchange Commission |
| WPSC | Wyoming Public Service Commission |
| WRDC | Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings |

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

| | Three Months Ended | | Nine Months Ended | |
|--|--|------------|-------------------|-------------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| | (in thousands, except per share amounts) | | | |
| Operating revenue: | | | | |
| Utilities | \$223,714 | \$212,193 | \$834,463 | \$821,027 |
| Non-regulated energy | 32,746 | 37,301 | 98,422 | 111,305 |
| Total operating revenue | 256,460 | 249,494 | 932,885 | 932,332 |
| Operating expenses: | | | | |
| Utilities - | | | | |
| Fuel, purchased power and cost of gas sold | 86,127 | 86,933 | 400,465 | 420,747 |
| Operations and maintenance | 58,313 | 57,294 | 184,411 | 188,357 |
| Gain on sale of operating assets | — | (6,238) |) — | (8,921) |
| Non-regulated energy operations and maintenance | 27,898 | 26,018 | 85,468 | 74,084 |
| Depreciation, depletion and amortization | 33,374 | 30,036 | 97,695 | 88,691 |
| Taxes - property, production and severance | 9,050 | 7,426 | 24,510 | 20,142 |
| Other operating expenses | 259 | 83 | 562 | 753 |
| Total operating expenses | 215,021 | 201,552 | 793,111 | 783,853 |
| Operating income | 41,439 | 47,942 | 139,774 | 148,479 |
| Other income (expense): | | | | |
| Interest charges - | | | | |
| Interest expense incurred (including amortization of debt issuance costs, premium and discount, realized settlements on interest rate swaps) | (29,697) |) (27,827) |) (88,418) |) (78,941) |
| Allowance for funds used during construction - borrowed | 3,520 | 1,934 | 9,874 | 7,804 |
| Capitalized interest | 2,981 | 1,614 | 8,198 | 2,470 |
| Interest rate swaps - unrealized (loss) gain | (38,246) |) (13,710) |) (40,608) |) (41,663) |
| Interest income | 563 | 199 | 1,598 | 529 |
| Allowance for funds used during construction - equity | 189 | 375 | 676 | 2,663 |
| Other income, net | 524 | 539 | 1,761 | 2,225 |
| Total other income (expense) | (60,166) |) (36,876) |) (106,919) |) (104,913) |
| Income (loss) before equity in earnings (loss) of unconsolidated subsidiaries and income taxes | (18,727) |) 11,066 | 32,855 | 43,566 |
| Equity in earnings (loss) of unconsolidated subsidiaries | 43 | (137) |) 1,076 | 1,471 |
| Income tax benefit (expense) | 8,159 | 1,461 | (9,794) |) (9,872) |
| Net income (loss) | \$(10,525) |) \$12,390 | \$24,137 | \$35,165 |
| Weighted average common shares outstanding: | | | | |

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| | | | | |
|--|---------|---------|---------|---------|
| Basic | 39,145 | 38,933 | 39,105 | 38,895 |
| Diluted | 39,145 | 39,133 | 39,792 | 39,052 |
| Earnings (loss) per share - basic | \$(0.27 |)\$0.32 | \$0.62 | \$0.90 |
| Earnings (loss) per share - diluted | \$(0.27 |)\$0.32 | \$0.61 | \$0.90 |
| Dividends paid per share of common stock | \$0.365 | \$0.360 | \$1.095 | \$1.080 |

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)

| | September 30, 2011 (in thousands) | December 31, 2010 | September 30, 2010 |
|---|---|----------------------|-----------------------|
| ASSETS | | | |
| Current assets: | | | |
| Cash and cash equivalents | \$74,779 | \$32,438 | \$58,975 |
| Restricted cash | 4,080 | 4,260 | 17,082 |
| Accounts receivable, net | 241,831 | 328,811 | 234,480 |
| Materials, supplies and fuel | 134,463 | 139,677 | 145,251 |
| Derivative assets, current | 48,727 | 56,572 | 71,688 |
| Income tax receivable, net | 10,958 | — | 25,156 |
| Deferred income tax assets, current | 39,628 | 17,113 | 15,073 |
| Regulatory assets, current | 45,713 | 66,429 | 55,941 |
| Other current assets | 65,889 | 25,571 | 20,932 |
| Total current assets | 666,068 | 670,871 | 644,578 |
| Investments | 17,338 | 17,780 | 17,981 |
| Property, plant and equipment | 3,664,967 | 3,359,762 | 3,243,641 |
| Less accumulated depreciation and depletion | (934,112) |) (864,329) |) (880,938) |
| Total property, plant and equipment, net | 2,730,855 | 2,495,433 | 2,362,703 |
| Other assets: | | | |
| Goodwill | 354,831 | 354,831 | 353,734 |
| Intangible assets, net | 3,899 | 4,069 | 4,129 |
| Derivative assets, non-current | 17,215 | 9,260 | 12,762 |
| Regulatory assets, non-current | 142,267 | 138,405 | 124,134 |
| Other assets, non-current | 20,894 | 20,860 | 20,216 |
| Total other assets | 539,106 | 527,425 | 514,975 |
| TOTAL ASSETS | \$3,953,367 | \$3,711,509 | \$3,540,237 |

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)

| | September 30, 2011 | December 31, 2010 | September 30, 2010 |
|--|--------------------------------------|----------------------|-----------------------|
| | (in thousands, except share amounts) | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | |
| Current liabilities: | | | |
| Accounts payable | \$219,167 | \$279,069 | \$201,072 |
| Accrued liabilities | 168,640 | 170,301 | 166,977 |
| Derivative liabilities, current | 129,163 | 79,167 | 108,318 |
| Accrued income taxes, net | — | 779 | — |
| Regulatory liabilities, current | 10,568 | 3,943 | 12,368 |
| Notes payable | 359,000 | 249,000 | 145,000 |
| Current maturities of long-term debt | 2,893 | 5,181 | 5,314 |
| Total current liabilities | 889,431 | 787,440 | 639,049 |
| Long-term debt, net of current maturities | 1,282,194 | 1,186,050 | 1,188,293 |
| Deferred credits and other liabilities: | | | |
| Deferred income tax liabilities, non-current | 329,833 | 277,136 | 279,315 |
| Derivative liabilities, non-current | 26,603 | 21,361 | 25,892 |
| Regulatory liabilities, non-current | 85,074 | 84,611 | 79,393 |
| Benefit plan liabilities | 124,214 | 124,709 | 122,178 |
| Other deferred credits and other liabilities | 128,013 | 129,932 | 125,710 |
| Total deferred credits and other liabilities | 693,737 | 637,749 | 632,488 |
| Stockholders' equity: | | | |
| Common stockholders' equity — | | | |
| Common stock \$1 par value; 100,000,000 shares authorized; issued 39,491,616, 39,280,048 and 39,243,257 shares, respectively | 39,492 | 39,280 | 39,243 |
| Additional paid-in capital | 604,945 | 598,805 | 597,108 |
| Retained earnings | 467,043 | 486,075 | 466,691 |
| Treasury stock at cost – 28,041, 10,962 and 7,905 shares, respectively | (810 |) (309 |) (226 |
| Accumulated other comprehensive income (loss) | (22,665 |) (23,581 |) (22,409 |
| Total stockholders' equity | 1,088,005 | 1,100,270 | 1,080,407 |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | \$3,953,367 | \$3,711,509 | \$3,540,237 |

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 September 30, | |
|--|------------------------------------|-----------|
| | 2011 | 2010 |
| | (in thousands) | |
| Operating activities: | | |
| Net income (loss) | \$24,137 | \$35,165 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 97,695 | 88,691 |
| Derivative fair value adjustments | 9,605 | (10,690) |
| Gain on sale of operating assets | — | (8,921) |
| Stock compensation | 4,931 | 2,908 |
| Unrealized mark-to-market loss (gain) on interest rate swaps | 40,608 | 41,663 |
| Deferred income taxes | 26,280 | 32,366 |
| Equity in (earnings) loss of unconsolidated subsidiaries | (1,076) | (1,471) |
| Allowance for funds used during construction - equity | (676) | (2,663) |
| Employee benefit plans | 10,930 | 12,214 |
| Other, net | 9,702 | 6,663 |
| Changes in certain operating assets and liabilities: | | |
| Materials, supplies and fuel | 12,592 | (40,344) |
| Accounts receivable and other current assets | 29,631 | 8,754 |
| Accounts payable and other current liabilities | (73,489) | (21,295) |
| Regulatory assets | 22,357 | (2,205) |
| Regulatory liabilities | 5,041 | 7,176 |
| Contributions to defined pension plans | (11,050) | (30,015) |
| Other operating activities | (691) | 7,765 |
| Net cash provided by operating activities | 206,527 | 125,761 |
| Investing activities: | | |
| Property, plant and equipment additions | (328,496) | (323,883) |
| Proceeds from sale of operating assets | 583 | 68,105 |
| Payment for acquisition of assets | — | (2,250) |
| Other investing activities | 1,051 | 4,273 |
| Net cash provided by (used in) investing activities | (326,862) | (253,755) |
| Financing activities: | | |
| Dividends paid | (43,169) | (42,331) |
| Common stock issued | 2,199 | 3,073 |
| Short-term borrowings - issuances | 770,000 | 451,500 |
| Short-term borrowings - repayments | (560,000) | (471,000) |
| Long-term debt - issuances | — | 200,000 |
| Long-term debt - repayments | (6,169) | (57,550) |
| Other financing activities | (185) | (9,624) |
| Net cash provided by (used in) financing activities | 162,676 | 74,068 |

| | | | |
|--|----------|----------|---|
| Net change in cash and cash equivalents | 42,341 | (53,926 |) |
| Cash and cash equivalents, beginning of period | 32,438 | 112,901 | |
| Cash and cash equivalents, end of period | \$74,779 | \$58,975 | |

See Note 3 for supplemental disclosure of cash flow information.

The accompanying notes to condensed consolidated financial statements are an integral part of these condensed consolidated financial statements.

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BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)

(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2010 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The condensed consolidated financial statements included herein have been prepared by Black Hills Corporation together with our subsidiaries (the "Company," "us," "we," or "our") without audit, 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 quarterly financial statements should be read in conjunction with the financial statements and the notes thereto included in our 2010 Annual Report on Form 10-K filed with the SEC.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying condensed quarterly financial statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2011, December 31, 2010 and September 30, 2010 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2011 and September 30, 2010, and our financial condition as of September 30, 2011, December 31, 2010, and September 30, 2010 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.

Certain prior year data presented in the accompanying condensed consolidated financial statements has been reclassified to conform to the current year presentation. Specifically, (a) the Company has reclassified revenue into two categories: Utilities revenue and Non-regulated energy revenue, (b) the categories of Fuel, purchased power and cost of gas sold and Operations and maintenance included in our Operating expenses have been reclassified into Utilities and Non-regulated energy, and (c) the Taxes - property, production and severance line has been reclassified to show only those taxes. Any taxes other than property, production and severance are now included in the respective Utility or Non-regulated energy operations and maintenance lines. Income taxes remain as a separate line item. These reclassifications had no effect on total assets, net income, cash flows or earnings per share.

Restatement - Subsequent to the issuance of the Company's 2010 consolidated financial statements, the Company's management determined that certain intercompany transactions with our rate regulated operations had not been properly eliminated in consolidation, resulting in an overstatement of Utility and Non-regulated energy revenue and Fuel, purchased power and cost of gas sold of \$14.8 million and \$45.6 million, in aggregate for the three and nine months ended September 30, 2010, respectively. As such, the condensed consolidated financial statements have been restated for the correction of this error. The correction did not have an impact on our gross margin, net income, total assets or cash flows.

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

Recently Adopted Accounting Standards and Legislation

Fair Value Measurements, ASC 820

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements, disclosure of inputs and techniques used in valuation and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements is required to be presented separately. These disclosures are required for interim and annual reporting periods and were effective for us on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. The guidance required additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 13 of these Notes to Condensed Consolidated Financial Statements.

Patient Protection and Affordable Care Act

In March 2010, the President of the United States signed into law comprehensive healthcare reform legislation under the PPACA as amended by the Healthcare and Education Reconciliation Act. The total potential impact on the Company, if any, cannot be determined until regulations are promulgated under the PPACA. Included among the provisions of the PPACA is a change in the tax treatment of the Medicare Part D subsidy (the "subsidy"), which affects our Non-Pension Postretirement Benefit Plan. Internal Revenue Code Section 139A has been amended to eliminate the deduction of the subsidy in reducing income for years beginning after December 31, 2012. The impact of this change in the tax treatment of the subsidy had an immaterial effect on our financial position, results of operations and cash flows. The Company will continue to assess the implications on our financial statements of the PPACA as related regulations and interpretations become available.

Recently Issued Accounting Standards and Legislation

Intangibles - Goodwill and Other, ASU No. 2011-08

The FASB issued an accounting standards update amending ASC 350 which permits entities to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If an entity believes, as a result of its qualitative assessment, that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the quantitative two-step goodwill impairment test is required. An entity has the unconditional option to bypass the qualitative assessment and proceed directly to performing the first step of the goodwill impairment test. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed in fiscal years beginning after December 15, 2011 with early adoption permitted.

Other Comprehensive Income, ASU No. 2011-05

FASB issued an accounting standards update amending ASC 220 to improve the comparability, consistency and transparency of reporting of comprehensive income. The update amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial

statements. ASU No. 2011-05 requires retrospective application, and it is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. The adoption of this update may change the order in which certain financial statements are presented and provide additional detail on those financial statements when applicable, but will not have any other impact on our consolidated financial statements.

Fair Value Measurement, ASU No. 2011-04

FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements, quantitative information about unobservable inputs used, a description of the valuation processes used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a non-financial asset that is different from the asset's highest and best use, the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required, the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosure of all transfers between Level 1 and Level 2 of the fair value hierarchy. ASU No. 2011-04 is effective for fiscal years, and interim periods within those years, beginning after December 31, 2011, with early adoption permitted. We do not expect this amendment to have an impact on our financial position, results of operations, or cash flows.

Dodd-Frank Wall Street Reform and Consumer Protection Act

In July 2010, the President of the United States signed into law comprehensive financial reform legislation under Dodd-Frank. Title VII of Dodd-Frank effectively regulates many derivative transactions in the United States that were previously unregulated, including swap transactions in the over-the-counter market. Among other things, Dodd-Frank (i) mandates the clearing of some swaps through regulated central clearing organizations and the trading of clearing swaps through regulated exchanges or swap execution facilities, in each case subject to certain key exemptions, and (ii) authorizes regulators to establish collateral and margin requirements for certain swap transactions that are not cleared. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, and includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. Significant rule-making by numerous governmental agencies, particularly the CFTC with respect to non-security commodities, will be required in order to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank. We will continue to evaluate the impact as these rules become available.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

| | Nine Months Ended | |
|---|-----------------------|-----------------------|
| | September 30, 2011 | September 30, 2010 |
| | (in thousands) | |
| Non-cash investing activities— | | |
| Property, plant and equipment acquired with accrued liabilities | \$49,566 | \$37,661 |
| Cash (paid) refunded during the period for— | | |
| Interest (net of amounts capitalized) | \$(61,461) | \$(62,740) |
| Income taxes, net | \$11,826 | \$(488) |

(4) MATERIALS, SUPPLIES AND FUEL

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

| | September 30, 2011 | December 31, 2010 | September 30, 2010 |
|--|-----------------------|----------------------|-----------------------|
| Materials and supplies | \$37,611 | \$31,749 | \$31,192 |
| Fuel - Electric Utilities | 8,639 | 9,687 | 9,056 |
| Natural gas in storage — Gas Utilities | 38,641 | 21,691 | 36,782 |
| Commodities held by Energy Marketing* | 49,572 | 76,550 | 68,221 |
| Total materials, supplies and fuel | \$134,463 | \$139,677 | \$145,251 |

* As of September 30, 2011, December 31, 2010 and September 30, 2010, market adjustments related to natural gas held by Energy Marketing and recorded in inventory as part of fair value hedge transactions were \$(1.7) million, \$(9.1) million and \$(18.7) million, respectively (see Note 12 for further discussion of Energy Marketing activities).

(5) ACCOUNTS RECEIVABLE

Trade Accounts Receivable

Our Accounts receivable represents primarily customer trade accounts at our Electric Utilities and Gas Utilities segments and counterparty trade accounts at our Energy Marketing segment. This balance fluctuates primarily due to the seasonality of our Gas Utilities and volume and commodity prices at our Energy Marketing segment. We maintain an allowance for doubtful accounts that reflects our best estimate of probable uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect our ability to collect. Following is a summary of receivables (in thousands):

| As of | Accounts Receivable, Trade | Unbilled Revenue | Total Accounts Receivable | Less Allowance for Accounts Doubtful | Accounts Receivable, net |
|--------------------|-------------------------------|---------------------|------------------------------|---|--------------------------|
| September 30, 2011 | | | | | |
| Electric | \$41,889 | \$16,401 | \$58,290 | \$(590) |)\$57,700 |
| Gas | 21,168 | 12,518 | 33,686 | (789) |)32,897 |
| Oil and Gas | 8,820 | — | 8,820 | (161) |)8,659 |
| Coal Mining | 1,845 | — | 1,845 | — | 1,845 |
| Energy Marketing | 139,332 | — | 139,332 | (174) |)139,158 |
| Power Generation | 119 | — | 119 | — | 119 |
| Corporate | 1,453 | — | 1,453 | — | 1,453 |
| Total | \$214,626 | \$28,919 | \$243,545 | \$(1,714) |)\$241,831 |

| As of | Accounts | Unbilled | Total Accounts | Less Allowance for Accounts | |
|-------------------|-------------------|----------|----------------|-----------------------------|-----------------|
| December 31, 2010 | Receivable, Trade | Revenue | Receivable | Doubtful Accounts | Receivable, net |
| Electric | \$51,005 | \$19,572 | \$70,577 | \$(708) |)\$69,869 |
| Gas | 41,970 | 40,376 | 82,346 | (1,425) |)80,921 |
| Oil and Gas | 6,213 | — | 6,213 | (161) |)6,052 |
| Coal Mining | 2,420 | — | 2,420 | — | 2,420 |
| Energy Marketing | 157,064 | — | 157,064 | (69) |)156,995 |
| Power Generation | 307 | — | 307 | — | 307 |
| Corporate (a) | 12,247 | — | 12,247 | — | 12,247 |
| Total | \$271,226 | \$59,948 | \$331,174 | \$(2,363) |)\$328,811 |

| As of | Accounts | Unbilled | Total Accounts | Less Allowance for Accounts | |
|--------------------|-------------------|----------|----------------|-----------------------------|-----------------|
| September 30, 2010 | Receivable, Trade | Revenue | Receivable | Doubtful Accounts | Receivable, net |
| Electric | \$41,955 | \$17,959 | \$59,914 | \$(927) |)\$58,987 |
| Gas | 19,611 | 11,107 | 30,718 | (830) |)29,888 |
| Oil and Gas | 6,112 | — | 6,112 | (161) |)5,951 |
| Coal Mining | 2,201 | — | 2,201 | — | 2,201 |
| Energy Marketing | 99,850 | — | 99,850 | (375) |)99,475 |
| Power Generation | 463 | — | 463 | — | 463 |
| Corporate (a) (b) | 37,515 | — | 37,515 | — | 37,515 |
| Total | \$207,707 | \$29,066 | \$236,773 | \$(2,293) |)\$234,480 |

(a) During the third quarter of 2010 we reached a settlement with the IRS and received a refund relating to this settlement during 2011 of \$12.0 million, excluding interest income.

(b) includes cash collateral receivable on de-designated interest rate swaps. See Note 12 for further information.

(6) NOTES PAYABLE

Our credit facilities and debt securities contain certain restrictive covenants including, among others, recourse leverage ratios and consolidated net worth covenants. As of September 30, 2011, we were in compliance with these covenants. Our credit facilities and debt securities do not contain default provisions pertaining to our credit ratings.

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

| | As of September 30, 2011 | | As of December 31, 2010 | | As of September 30, 2010 | |
|---------------------------|--------------------------|-------------------|-------------------------|-------------------|--------------------------|-------------------|
| | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit | Balance Outstanding | Letters of Credit |
| Revolving Credit Facility | \$209,000 | \$42,355 | \$149,000 | \$46,900 | \$145,000 | \$15,500 |
| Enserco Credit Facility | — | 132,625 | — | 166,900 | — | 131,500 |
| Term Loan due 2011 | — | — | 100,000 | — | — | — |
| Term Loan due 2012 | 150,000 | — | — | — | — | — |
| Total | \$359,000 | \$174,980 | \$249,000 | \$213,800 | \$145,000 | \$147,000 |

Revolving Credit Facility

Our \$500.0 million Revolving Credit Facility expiring April 14, 2013 contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to \$600.0 million and can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 1.75%, 2.75% and 2.75%, respectively, at September 30, 2011. The facility contains a commitment fee to be charged on the unused amount of the facility. Based upon current credit ratings, the fee is 0.5%.

Deferred financing costs are being amortized over the term of the facility. The amortization expense is included in Interest expense on the accompanying Condensed Consolidated Statements of Income as follows (in thousands):

| | Deferred Financing Costs Remaining on Balance Sheet as of September 30, 2011 | Amortization Expense | | | |
|--|---|-------------------------------------|-------|------------------------------------|-------|
| | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| | | 2011 | 2010 | 2011 | 2010 |
| Deferred Financing Costs - Revolving Credit Facility | \$1,970 | \$473 | \$481 | \$1,419 | \$866 |

The Revolving Credit Facility includes the following covenants that we must comply with at the end of each quarter (dollars in thousands). We were in compliance with these covenants as of September 30, 2011.

| As of September 30, 2011 | Actual | Covenant Requirement | |
|--------------------------|-------------|-------------------------|---|
| Consolidated Net Worth | \$1,088,000 | \$871,300 | |
| Recourse Leverage Ratio | 61.3 | % 65.0 | % |

Enserco Credit Facility

Enserco's \$250.0 million committed credit facility expiring May 7, 2012 contains an accordion feature which allows, with the consent of the administrative agent, the commitment under the facility to increase to \$350.0 million. Maximum borrowings under the facility are subject to a sub-limit of \$50.0 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%. Enserco Credit Facility covenants include tangible net worth, net working capital and realized net working capital requirements. Enserco was in compliance with these covenants as of September 30, 2011.

Deferred financing costs for the Enserco Credit Facility are being amortized over the term of the Enserco Credit Facility. The amortization expense is included in Interest expense on the accompanying Condensed Consolidated Statements of Income as follows (in thousands):

| | Deferred Financing Costs Remaining on Balance Sheet as of September 30, 2011 | Amortization Expense | | | |
|--|---|-------------------------------------|-------|------------------------------------|---------|
| | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| | | 2011 | 2010 | 2011 | 2010 |
| Deferred Financing Costs - Enserco Credit Facility | \$812 | \$305 | \$263 | \$866 | \$1,245 |

Corporate Term Loans

On September 30, 2011, we extended our \$100.0 million term loan for two-years under the existing terms. This term loan is now due on September 30, 2013.

In June 2011, we entered into a one-year \$150.0 million unsecured, single draw, term loan with CoBank, the Bank of Nova Scotia and U.S. Bank due on June 24, 2012. The cost of borrowing under the loan is based on a spread of 125 basis points over LIBOR (1.63% at September 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility. We were in compliance with these covenants as of September 30, 2011.

(7) EARNINGS PER SHARE

Basic earnings (loss) per share is computed by dividing net income by the weighted-average number of common shares outstanding during the period. Diluted earnings (loss) per share is computed by using all dilutive common shares potentially outstanding during a period. A reconciliation of share amounts used to compute earnings (loss) per share is as follows (in thousands):

| | Three Months Ended September 30, 2011 | | September 30, 2010 | |
|-----------------------------------|---|-----------|-----------------------|----------|
| Net income (loss) | \$(10,525 |)\$12,390 | \$24,137 | \$35,165 |
| Weighted average shares - basic | 39,145 | 38,933 | 39,105 | 38,895 |
| Dilutive effect of: | | | | |
| Restricted stock | — | 131 | 147 | 110 |
| Stock options | — | 12 | 16 | 9 |
| Forward equity issuance | — | — | 473 | — |
| Other | — | 57 | 51 | 38 |
| Weighted average shares - diluted | 39,145 | 39,133 | 39,792 | 39,052 |

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

Due to the Company's net loss in the quarter ending September 30, 2011, potentially dilutive securities, consisting of outstanding stock options, restricted common stock, restricted stock units, non-vested performance-based share awards, warrants and forward equity instruments were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 11,880 options to purchase shares of common stock, 159,873 vested and non-vested restricted stock shares, 31,408 warrants and other performance shares and 424,715 forward equity instruments were excluded from the computations for the three months ended September 30, 2011.

In addition to these potentially dilutive shares, 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 September 30, 2011 | | September 30, 2010 | |
|---------------|---|-----|-----------------------|-----|
| Stock options | 176 | 128 | 119 | 169 |

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| | | | | |
|----------------------|-----|-----|-----|-----|
| Restricted stock | 20 | 2 | 17 | 2 |
| Other stock | 27 | 1 | 19 | 1 |
| Anti-dilutive shares | 223 | 131 | 155 | 172 |

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(8) COMPREHENSIVE INCOME (LOSS)

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

| | Three Months Ended September 30, 2011 |
|--|--|
| Net income (loss) | \$(10,525) |
| Other comprehensive income (loss), net of tax: | |
| Benefit plan liability adjustments | \$— |
| Taxes on benefit plan liability adjustments | — |
| Benefit plan liability adjustments, net of tax | — |
| Fair value adjustment on derivatives designated as cash flow hedges | \$3,137 |
| Taxes on fair value adjustment on derivatives designated as cash flow hedges | (1,215) |
| Fair value adjustment on derivatives designated as cash flow hedges, net of tax | 1,922 |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss) | \$414 |
| Taxes on reclassification adjustment on cash flow hedges settled and included in net income (loss) | (129) |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax | 285 |
| Comprehensive income (loss) | \$(8,318) |
| | Three Months Ended September 30, 2010 |
| Net income (loss) | \$12,390 |
| Other comprehensive income (loss), net of tax: | |
| Benefit plan liability adjustments | \$— |
| Taxes on benefit plan liability adjustments | — |
| Benefit plan liability adjustments, net of tax | — |
| Fair value adjustment on derivatives designated as cash flow hedges | \$517 |
| Taxes on fair value adjustment on derivatives designated as cash flow hedges | 486 |
| Fair value adjustment on derivatives designated as cash flow hedges, net of tax | 1,003 |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss) | \$(4,730) |
| Taxes on reclassification adjustment on cash flow hedges settled and included in net income (loss) | 1,761 |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax | (2,969) |
| Comprehensive income (loss) | \$10,424 |

| | Nine Months Ended September 30, 2011 | |
|--|---|----------|
| Net income (loss) | | \$24,137 |
| Other comprehensive income (loss), net of tax: | | |
| Benefit plan liability adjustments | \$— | |
| Taxes on benefit plan liability adjustments | — | |
| Benefit plan liability adjustments, net of tax | | — |
| Fair value adjustment on derivatives designated as cash flow hedges | \$(1,644 |) |
| Taxes on fair value adjustment on derivatives designated as cash flow hedges | 653 | |
| Fair value adjustment on derivatives designated as cash flow hedges, net of tax | | (991) |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss) | \$2,892 | |
| Taxes on reclassification adjustment on cash flow hedges settled and included in net income (loss) | (985 |) |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax | | 1,907 |
| Comprehensive income (loss) | | \$25,053 |
| | | |
| | Nine Months Ended September 30, 2010 | |
| Net income (loss) | | \$35,165 |
| Other comprehensive income (loss), net of tax: | | |
| Benefit plan liability adjustments | \$(8 |) |
| Taxes on benefit plan liability adjustments | (7 |) |
| Benefit plan liability adjustments, net of tax | | (15) |
| Fair value adjustment on derivatives designated as cash flow hedges | \$495 | |
| Taxes on fair value adjustment on derivatives designated as cash flow hedges | 641 | |
| Fair value adjustment on derivatives designated as cash flow hedges, net of tax | | 1,136 |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss) | \$(6,909 |) |
| Taxes on reclassification adjustment on cash flow hedges settled and included in net income (loss) | 2,543 | |
| Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax | | (4,366) |
| Comprehensive income (loss) | | \$31,920 |

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

| | September 30, 2011 | | December 31, 2010 | | September 30, 2010 | |
|--|-----------------------|---|----------------------|---|-----------------------|---|
| Derivatives designated as cash flow hedges | \$(11,523 |) | \$(12,437 |) | \$(12,741 |) |
| Benefit plans | (11,142 |) | (11,142 |) | (9,636 |) |
| Amount from equity-method investees | — | | (2 |) | (32 |) |
| Total | \$(22,665 |) | \$(23,581 |) | \$(22,409 |) |

(9) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the nine months ended September 30, 2011 from the amount reported in Note 11 of the Notes to Consolidated Financial Statements in our 2010 Annual Report on Form 10-K.

Equity Compensation Plans

We granted 67,389 target performance shares to certain officers and business unit leaders for the January 1, 2011 through December 31, 2013 performance period during the nine months ended September 30, 2011. Actual shares are issued after the end of the performance plan period. Performance shares are awarded based on our total stockholder return over the designated performance period as measured against a selected peer group and can range from 0% to 175% of target. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria. The performance awards are paid 50% in the form of cash and 50% in shares of common stock. The grant date fair value was \$25.91 per share.

We issued 14,111 shares of common stock under our short-term incentive compensation plan during the nine months ended September 30, 2011. Pre-tax compensation cost related to the awards was approximately \$0.4 million, which was expensed in 2010.

We granted 136,348 shares of restricted common stock and restricted stock units during the nine months ended September 30, 2011. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately \$4.1 million will be recognized over the three year vesting period.

We granted 99,000 stock options at a weighted-average exercise price of \$32.04 during the nine months ended September 30, 2011. The total fair value of approximately \$0.6 million will be recognized over the three year vesting period.

Stock options totaling 5,500 shares were exercised during the nine months ended September 30, 2011 at a weighted-average exercise price of \$29.94 per share, providing \$0.2 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended September 30, 2011 and 2010 was \$1.7 million and \$1.9 million, respectively, and for the nine months ended September 30, 2011 and 2010 was \$5.0 million and \$4.7 million, respectively.

As of September 30, 2011, total unrecognized compensation expense related to non-vested stock awards was \$8.5 million and is expected to be recognized over a weighted-average period of 2 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which stockholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued 79,339 new shares at a weighted-average price of \$30.81 during the nine months ended September 30, 2011. At September 30, 2011, 476,437 shares of unissued common stock were available for future offering under the DRIP.

Dividend Restrictions

Our Revolving Credit Facility contains restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: a recourse leverage ratio not to exceed 0.65 to 1.00 and a minimum consolidated net worth of \$625 million plus 50.0% of aggregate consolidated net income, if positive, since January 1, 2005. As of September 30, 2011, 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 as of September 30, 2011:

Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may be subject to further restrictions under the Federal Power Act. As of September 30, 2011, the restricted net assets at our Utilities Group were approximately \$164.3 million.

Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, Enserco may be restricted from making dividend payments to its parent company. Enserco's restricted net assets at September 30, 2011 were \$163.8 million.

Pursuant to a covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of \$100.0 million. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation, which is the parent of Black Hills Wyoming.

Forward Equity Instrument

In November 2010, we entered into a Forward Equity Agreement in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. In December 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares under the same terms as the original Forward Equity Agreement. We settled the equity forward instrument on November 1, 2011 by physically delivering 4,413,519 shares of common stock in exchange for proceeds of approximately \$120 million.

(10) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

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

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

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| | Three Months Ended | | Nine Months Ended | |
|--------------------------------|--------------------|----------|-------------------|-----------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Service cost | \$1,355 | \$1,533 | \$4,066 | \$4,599 |
| Interest cost | 3,732 | 3,773 | 11,196 | 11,319 |
| Expected return on plan assets | (4,239 |) (3,623 |) (12,717 |) (10,869 |
| Prior service cost | 25 | 305 | 75 | 915 |
| Net loss (gain) | 1,135 | 500 | 3,405 | 1,500 |
| Curtailment expense | — | — | — | — |
| Net periodic benefit cost | \$2,008 | \$2,488 | \$6,025 | \$7,464 |

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Non-pension Defined Benefit Postretirement Healthcare Plans

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

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

| | Three Months Ended | | Nine Months Ended | |
|--------------------------------|--------------------|---------|-------------------|---------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Service cost | \$375 | \$377 | \$1,125 | \$1,131 |
| Interest cost | 542 | 611 | 1,626 | 1,833 |
| Expected return on plan assets | (41 |) (52 |) (123 |) (156 |
| Prior service benefit | (120 |) (77 |) (360 |) (231 |
| Net transition obligation | — | — | — | — |
| Net loss (gain) | 169 | 159 | 507 | 477 |
| Net periodic benefit cost | \$925 | \$1,018 | \$2,775 | \$3,054 |

It has been determined that our post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

Supplemental Non-qualified Defined Benefit Plans

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

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

| | Three Months Ended | | Nine Months Ended | |
|---------------------------|--------------------|-------|-------------------|---------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Service cost | \$257 | \$171 | \$771 | \$513 |
| Interest cost | 324 | 321 | 973 | 963 |
| Prior service cost | 1 | 1 | 3 | 3 |
| Net loss (gain) | 128 | 71 | 383 | 213 |
| Net periodic benefit cost | \$710 | \$564 | \$2,130 | \$1,692 |

Contributions

We anticipate that we will make contributions to each of the benefit plans during 2011 and 2012. Contributions to the Healthcare Plans and the Supplemental Plans expected to be made in the form of benefit payments are as follows (in thousands):

| | Contributions Made Three Months Ended September 30, 2011 | Contributions Made Nine Months Ended September 30, 2011 | Contributions Remaining for 2011 | Contributions Anticipated for 2012 |
|---|---|--|--|--|
| Defined Benefit Pension Plans | \$10,500 | \$11,050 | \$— | \$7,869 |
| Non-pension Defined Benefit Postretirement Healthcare Plans | \$882 | \$2,646 | \$882 | \$3,765 |
| Supplemental Non-qualified Defined Benefit Plans | \$235 | \$705 | \$236 | \$896 |

(11) SUMMARY OF INFORMATION RELATING TO SEGMENTS OF OUR BUSINESS

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. As of September 30, 2011, substantially all of our operations and assets were located within the United States.

We conduct our operations through the following six reportable segments:

Utilities Group —

• Electric Utilities, which supplies electric utility service to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility service to Cheyenne, Wyoming and vicinity; and

• Gas Utilities, which supplies natural gas utility service to areas in Colorado, Iowa, Kansas and Nebraska.

Non-regulated Energy Group —

• Oil and Gas, which produces, explores and operates oil and natural gas interests located in the Rocky Mountain region and other states;

• Power Generation, which produces and sells power and capacity to wholesale customers from power plants located in Wyoming. Additionally, in 2009 our Power Generation segment entered into a 20-year PPA to supply Colorado Electric with 200 MW of capacity and energy from power plants under construction in Colorado, which are expected to be placed into service by December 31, 2011. In January 2011, we sold our ownership interests in the partnerships which owned the generation facilities in Idaho;

• Coal Mining, which engages in the mining and sale of coal from our mine near Gillette, Wyoming; and

• Energy Marketing, which provides natural gas, crude oil, coal, power and environmental marketing and related services in the United States and Canada.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 2010 Annual Report on Form 10-K.

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

| Three Months Ended September 30, 2011 | External Operating Revenue | Inter-segment Operating Revenue | Net Income (Loss) |
|---------------------------------------|----------------------------------|--|----------------------|
| Utilities: | | | |
| Electric | \$151,063 | \$2,653 | \$15,790 |
| Gas | 72,651 | — | 572 |
| Non-regulated Energy: | | | |
| Oil and Gas | 19,163 | — | 241 |
| Power Generation | 1,011 | 7,089 | 337 |
| Coal Mining | 9,184 | 8,651 | 555 |
| Energy Marketing | 3,388 | 3,550 | 273 |
| Corporate ^(a) | — | — | (27,943) |
| Inter-segment eliminations | — | (21,943) | (350) |
| Total | \$256,460 | \$— | \$(10,525) |
| Three Months Ended September 30, 2010 | External Operating Revenue | Inter-segment Operating Revenue ^(d) | Net Income (Loss) |
| Utilities: | | | |
| Electric ^(b) | \$138,761 | \$2,884 | \$18,537 |
| Gas ^(c) | 72,323 | — | (595) |
| Non-regulated Energy: | | | |
| Oil and Gas ^(e) | 19,354 | — | 836 |
| Power Generation | 1,124 | 6,731 | 575 |
| Coal Mining | 7,744 | 6,533 | 1,673 |
| Energy Marketing | 9,060 | (87) | 1,370 |
| Corporate ^{(a) (f)} | — | — | (10,093) |
| Inter-segment eliminations | — | (14,933) | 87 |
| Total | \$248,366 | \$1,128 | \$12,390 |
| Nine Months Ended September 30, 2011 | External Operating Revenue | Inter-segment Operating Revenue | Net Income (Loss) |
| Utilities: | | | |
| Electric | \$431,624 | \$9,902 | \$34,653 |
| Gas | 402,839 | — | 24,275 |
| Non-regulated Energy: | | | |
| Oil and Gas | 55,907 | — | (553) |
| Power Generation | 2,750 | 20,750 | 2,071 |
| Coal Mining | 23,064 | 25,806 | (1,124) |
| Energy Marketing | 16,701 | 5,178 | 1,327 |
| Corporate ^(a) | — | — | (36,101) |
| Inter-segment eliminations | — | (61,636) | (411) |
| Total | \$932,885 | \$— | \$24,137 |

| Nine Months Ended September 30, 2010 | External Operating Revenue | Inter-segment Operating Revenue ^(d) | Net Income (Loss) |
|--------------------------------------|----------------------------------|--|----------------------|
| Utilities: | | | |
| Electric ^(b) | \$415,092 | \$11,627 | \$35,585 |
| Gas ^(c) | 402,608 | — | 18,017 |
| Non-regulated Energy: | | | |
| Oil and Gas ^(e) | 57,755 | — | 3,405 |
| Power Generation | 3,266 | 19,336 | 1,239 |
| Coal Mining | 22,431 | 20,875 | 6,093 |
| Energy Marketing | 27,797 | (157) | 4,890 |
| Corporate ^{(a) (f)} | — | — | (34,221) |
| Inter-segment eliminations | — | (48,298) | 157 |
| Total | \$928,949 | \$3,383 | \$35,165 |

(a) Net income (loss) includes a \$24.9 million and a \$26.4 million net after-tax mark-to-market loss on interest rate swaps for the three and nine months ended September 30, 2011 and an \$8.9 million and \$27.1 million net after-tax loss on interest rate swaps for the three and nine months ended September 30, 2010, respectively.

(b) Net income (loss) includes a \$4.1 million after-tax gain on sale of a 23% interest in Wygen III to the City of Gillette.

(c) Net income (loss) includes a \$1.7 million after-tax gain on sale of operating assets in the Gas Utilities at Nebraska Gas.

(d) Total operating revenue has been restated to reflect elimination of intercompany activities previously not eliminated. See Note 1 for further information.

(e) Net income (loss) includes a \$0.4 million reduction of income taxes as a result of a re-measurement of a previously reported uncertain tax position due to a settlement with the IRS.

(f) Net income (loss) includes a \$2.0 million reduction in income tax expense reflecting a re-measurement of an uncertain tax position due to a settlement agreement that was reached with the IRS primarily due to tax depreciation method changes.

| | September 30, 2011 | December 31, 2010 | September 30, 2010 |
|---------------------------------|-----------------------|----------------------|-----------------------|
| Total assets | | | |
| Utilities: | | | |
| Electric ^(a) | \$1,917,183 | \$1,834,019 | \$1,771,014 |
| Gas | 683,163 | 722,287 | 659,801 |
| Non-regulated Energy: | | | |
| Oil and Gas | 405,513 | 349,991 | 358,113 |
| Power Generation ^(a) | 372,313 | 293,334 | 249,778 |
| Coal Mining | 94,908 | 96,962 | 94,149 |
| Energy Marketing | 340,499 | 314,930 | 287,173 |
| Corporate | 139,788 | 99,986 | 120,209 |
| Total assets | \$3,953,367 | \$3,711,509 | \$3,540,237 |

(a) Includes construction of a 180 MW power generation facility by our Colorado Electric utility and a 200 MW power generation facility by our Power Generation segment; both facilities are currently under construction and are expected to be completed by December 31, 2011.

(12) 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 counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks:

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

Interest rate risk associated with variable rate credit facilities and changes in forward interest rates used to determine the mark-to-market adjustment on our interest rate swaps; and

Foreign currency exchange risk associated with marketing transacted in Canadian dollars.

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

We actively manage our exposure to certain market risks as described in Note 3 of the Notes to our Consolidated Financial Statements in our 2010 Annual Report on Form 10-K. Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income are detailed below and within Note 13.

Trading Activities

Our Energy Marketing segment is engaged in marketing natural gas, crude oil, coal, power and environmental products, specializing in producer services, end-use origination and wholesale marketing in the United States and Canada. Coal marketing activity began June 1, 2010, Power marketing began late in the third quarter of 2010, and Environmental marketing began late in the third quarter of 2010 with no significant activity until the second quarter of 2011.

Contracts and other activities at our Energy Marketing operations are accounted for under the accounting standards for energy trading contracts. As such, all of the contracts and other activities at our marketing operations that meet the definition of a derivative are accounted for at fair value. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenue in the accompanying Condensed Consolidated Statements of Income. Accounting for energy trading contracts precludes mark-to-market accounting for energy trading contracts that are not defined as derivatives pursuant to accounting standards for derivatives. As part of our marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting for derivatives and hedging generally does not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas, crude oil and coal marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions results from these accounting requirements.

To effectively manage our portfolios, we enter into forward physical commodity contracts, financial derivative instruments including over-the-counter swaps and options, and storage and transportation agreements. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed in the BHCRRP and further delineated in the Energy Marketing Risk Management Policies and Procedures as approved by

our Executive Risk Committee.

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, index, storage, transportation and foreign exchange positions.

Daily risk management activities include reviewing positions in relation to established position limits, assessing changes in daily mark-to-market and other non-statistical risk management techniques.

The contract or notional amounts and terms of our marketing activities and derivative commodity instruments were as follows:

| | Outstanding at September 30, 2011 | | Outstanding at December 31, 2010 | | Outstanding at September 30, 2010 | |
|--|--------------------------------------|----------------------------------|-------------------------------------|----------------------------------|--------------------------------------|----------------------------------|
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| (notional in thousands of MMBtus) | | | | | | |
| Natural gas basis swaps purchased | 425,360 | 42 | 399,128 | 22 | 335,805 | 25 |
| Natural gas basis swaps sold | 443,489 | 42 | 426,903 | 22 | 358,929 | 25 |
| Natural gas fixed-for-float swaps purchased | 251,602 | 27 | 135,005 | 33 | 84,636 | 36 |
| Natural gas fixed-for-float swaps sold | 249,808 | 27 | 150,803 | 22 | 97,210 | 18 |
| Natural gas physical purchases | 105,446 | 27 | 144,948 | 36 | 135,818 | 18 |
| Natural gas physical sales | 122,232 | 72 | 143,021 | 36 | 136,530 | 36 |
| Natural gas futures purchased | 78,100 | 7 | — | — | — | — |
| Natural gas futures sold | 96,730 | 7 | — | — | — | — |
| Natural gas options purchased | 6,000 | 2 | — | — | — | — |
| Natural gas options sold | 6,000 | 2 | — | — | — | — |
| | | | | | | |
| | Outstanding at September 30, 2011 | | Outstanding at December 31, 2010 | | Outstanding at September 30, 2010 | |
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| (notional in thousands of Bbls) | | | | | | |
| Crude oil physical purchases | 7,326 | 15 | 5,628 | 16 | 5,561 | 15 |
| Crude oil physical sales | 7,917 | 15 | 6,921 | 16 | 4,759 | 15 |
| Crude oil fixed-for-float swaps purchased | — | — | 20 | 3 | 135 | 1 |
| Crude oil fixed-for-float swaps sold | 10 | 2 | 240 | 4 | 289 | 3 |
| | | | | | | |
| | Outstanding at September 30, 2011 | | Outstanding at December 31, 2010 | | Outstanding at September 30, 2010 | |
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| (notional in thousands of tons) | | | | | | |
| Coal fixed-for-float swaps purchased | 8,305 | 27 | 4,060 | 36 | 5,585 | 39 |
| Coal fixed-for-float swaps sold | 9,710 | 27 | 3,720 | 36 | 4,445 | 39 |
| Coal physical purchases | 27,982 | 39 | 24,634 | 48 | 24,100 | 51 |
| Coal physical sales | 13,331 | 39 | 9,046 | 36 | 6,213 | 35 |
| Coal options purchased | 4,530 | 51 | 2,835 | 48 | 1,980 | 27 |
| Coal options sold | 572 | 6 | 270 | 12 | 360 | 15 |

| (notional in thousands of MWh): | Outstanding at September 30, 2011 | | Outstanding at December 31, 2010 | | Outstanding at September 30, 2010 | |
|--|--------------------------------------|----------------------------------|-------------------------------------|----------------------------------|--------------------------------------|----------------------------------|
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| Power physical purchases | 153 | 54 | — | — | — | — |
| Power physical sales | 153 | 54 | — | — | — | — |
| Power fixed-for-float swaps purchased | 12,370 | 27 | — | — | — | — |
| Power fixed-for-float swaps sold | 12,439 | 27 | — | — | — | — |

| (notional in thousands of MWh): | Outstanding at September 30, 2011 | | Outstanding at December 31, 2010 | | Outstanding at September 30, 2010 | |
|--|--------------------------------------|----------------------------------|-------------------------------------|----------------------------------|--------------------------------------|----------------------------------|
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| Environmental products physical purchases | 283 | 54 | — | — | — | — |
| Environmental products physical sales | 273 | 54 | — | — | — | — |

Derivatives and certain other marketing transactions were marked to fair value at September 30, 2011, December 31, 2010 and September 30, 2010, and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income were as follows (in thousands):

| | September 30, 2011 | December 31, 2010 | September 30, 2010 |
|---|-----------------------|----------------------|-----------------------|
| Current derivative assets | \$36,550 | \$43,862 | \$55,366 |
| Non-current derivative assets | \$13,969 | \$6,635 | \$8,023 |
| Current derivative liabilities | \$27,851 | \$14,550 | \$17,743 |
| Non-current derivative liabilities | \$4,128 | \$3,464 | \$1,277 |
| Cash collateral receivable (payable) included in derivative assets/liabilities | \$9,026 | \$3,958 | \$(7,365) |
| Unrealized gains | \$9,514 | \$28,525 | \$51,734 |
| Net derivative assets (liabilities) with credit risk-related contingent features that require Enserco to maintain a specific credit rating | \$— | \$— | \$— |
| Cash collateral receivable included in Other current assets | \$34,642 | \$9,919 | \$1,854 |
| Cash collateral (payable) included in Other current liabilities | \$(802) | \$(1,079) | \$(1,079) |

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in fair value hedge transactions. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in Materials, supplies and fuel on the accompanying Condensed Consolidated Balance Sheets and the related unrealized gain or loss on the Condensed Consolidated Statements of Income, effectively offsetting the earnings impact of the unrealized gain or loss recognized on the associated derivative asset or liability described above. As of September 30, 2011, December 31, 2010 and September 30, 2010, the market adjustments recorded in inventory were \$(1.7) million, \$(9.1) million and \$(18.7) million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural "long" positions, or unhedged open positions, result in commodity price risk and variability to our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve our cash flows, and we have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee and are routinely reviewed by our Board of Directors.

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

The derivatives were marked to fair value and are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives is reported in Accumulated other comprehensive income (loss) and the ineffective portion, if any, is reported in earnings.

We had the following derivatives and related balances (dollars in thousands):

| | September 30, 2011 | | December 31, 2010 | | September 30, 2010 | |
|---|-------------------------|-------------------|-------------------------|-------------------|-------------------------|-------------------|
| | Crude Oil Swaps/Options | Natural Gas Swaps | Crude Oil Swaps/Options | Natural Gas Swaps | Crude Oil Swaps/Options | Natural Gas Swaps |
| Notional* | 414,000 | 4,957,250 | 424,500 | 6,821,800 | 484,500 | 8,109,800 |
| Maximum terms in years ** | 1.00 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Derivative assets, current | \$1,885 | \$6,937 | \$248 | \$7,675 | \$466 | \$8,816 |
| Derivative assets, non-current | \$2,529 | \$717 | \$19 | \$2,606 | \$216 | \$4,523 |
| Derivative liabilities, current | \$— | \$— | \$3,814 | \$— | \$3,224 | \$— |
| Derivative liabilities, non-current | \$— | \$7 | \$1,301 | \$— | \$497 | \$— |
| Pre-tax accumulated other comprehensive income (loss) included in Condensed Consolidated Balance Sheets | \$4,257 | \$7,647 | \$(5,313) | \$10,281 | \$(3,611) | \$13,339 |
| Earnings | \$157 | \$— | \$465 | \$— | \$572 | \$— |

* Crude oil in Bbls, gas in MMBtus

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

Based on September 30, 2011 market prices, an \$8.3 million gain would be realized and reported in pre-tax earnings during the next 12 months related to hedges of production. Estimated and actual realized gains will likely change during the next 12 months as market prices fluctuate.

Gas Utilities - Gas Hedges

Our Gas Utilities segment distributes natural gas in four states. During the winter heating season, our gas customers are exposed to the effect of volatile natural gas prices; therefore, as allowed or required by state utility commissions, we have entered into certain exchange traded transactions, which may include natural gas futures, options and basis swaps, to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives in accordance with accounting standards for derivatives and mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. Gains and losses, as well as option premiums upon settlement, on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated operations. Accordingly, the earnings impact is recognized in the Condensed Consolidated Statements of Income as a component of PGA costs when the related costs are recovered through our rates as part of PGA costs in operating revenue.

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

| (notional in MMBtus) | Outstanding at September 30, 2011 | | Outstanding at December 31, 2010 | | Outstanding at September 30, 2010 | |
|-----------------------------------|--------------------------------------|----------------------------------|-------------------------------------|----------------------------------|--------------------------------------|----------------------------------|
| | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) | Notional Amounts | Latest Expiration (months) |
| Natural gas futures purchased | 9,890,000 | 18 | 6,670,000 | 15 | 11,800,000 | 18 |
| Natural gas options purchased | 3,880,000 | 6 | 1,730,000 | 3 | 3,980,000 | 6 |
| Natural gas basis swaps purchased | — | — | — | — | — | — |

We had the following derivative balances related to the hedges in our gas utilities (in thousands):

| | September 30, 2011 | December 31, 2010 | September 30, 2010 |
|--|-----------------------|----------------------|-----------------------|
| Current derivative assets | \$3,355 | \$4,787 | \$6,685 |
| Non-current derivative assets | \$— | \$— | \$— |
| Non-current derivative liabilities | \$1,360 | \$1,620 | \$2,600 |
| Net unrealized gain (loss) included in regulatory assets or regulatory liabilities | \$(11,813) | \$(8,030) | \$(18,381) |
| Cash collateral receivable (payable) included in derivative assets/liabilities | \$12,058 | \$10,355 | \$20,519 |
| Option premium included in Derivative assets, current | \$1,750 | \$842 | \$1,947 |

Financing Activities

We are exposed to interest rate risk associated with fluctuations in the interest rate on our variable interest rate debt. To manage this risk, we have entered into floating-to-fixed interest rate swap agreements with the intention to convert the debt's variable interest rate to a fixed rate.

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

| | September 30, 2011 | | December 31, 2010 | | September 30, 2010 | |
|--|--------------------------------------|---|--------------------------------------|---|--------------------------------------|---|
| | Designated Interest Rate Swaps | Dedesignated Interest Rate Swaps* | Designated Interest Rate Swaps | Dedesignated Interest Rate Swaps* | Designated Interest Rate Swaps | Dedesignated Interest Rate Swaps* |
| Current notional amount | \$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 | 5.25 | 0.25 | 6.00 | 1.00 | 6.25 | 0.25 |
| Derivative liabilities, current | \$6,724 | \$94,588 | \$6,823 | \$53,980 | \$6,901 | \$80,450 |
| Derivative liabilities, non-current | \$21,108 | \$— | \$14,976 | \$— | \$21,518 | \$— |
| Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets | \$(27,832) | \$— | \$(21,799) | \$— | \$(28,419) | \$— |
| Pre-tax (loss) gain included in Condensed Consolidated Statements of Income | \$— | \$(40,608) | \$— | \$(15,193) | \$— | \$(41,663) |
| Cash collateral receivable (payable) included in accounts receivable | \$— | \$— | \$— | \$— | \$— | \$25,000 |

Maximum terms in years reflect the amended mandatory early termination dates. If the mandatory 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 million terminate in 7.25 years and de-designated swaps totaling \$150 million terminate in 17.25 years.

Based on September 30, 2011 market interest rates and balances related to our designated interest rate swaps, a loss of approximately \$6.7 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next 12 months as market interest rates change. Note 13 provides further information related to the swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Transactions

Our Energy Marketing segment conducts its marketing in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange rate risk for us. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollar. Any balances that represent Canadian transactions are translated to United States dollars at the end of each accounting period at the exchange rate in effect at the balance sheet dates.

We had outstanding forward contracts included in Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets as follows (dollars in thousands):

| | As of September 30, 2011 | | As of December 31, 2010 | | As of September 30, 2010 | |
|----------------------------|------------------------------|----------------------------|------------------------------|----------------------------|------------------------------|----------------------------|
| | Outstanding Notional Amounts | Latest Expiration (Months) | Outstanding Notional Amounts | Latest Expiration (Months) | Outstanding Notional Amounts | Latest Expiration (Months) |
| Canadian dollars purchased | \$— | — | \$15,000 | 1 | \$5,000 | 1 |
| Canadian dollars sold | \$— | — | \$— | — | \$— | — |

Our outstanding foreign exchange contracts had a fair value as follows (in thousands):

| | As of September 30, 2011 | As of December 31, 2010 | As of September 30, 2010 |
|--|--------------------------|-------------------------|--------------------------|
| Fair Value of foreign exchange contracts | \$— | \$(143 |)\$(11) |

The table below includes gains (losses) recognized for foreign exchange contracts and foreign exchange re-measurement of assets and liabilities to our functional currency included in Operating revenue on the accompanying Condensed Consolidated Statements of Income (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|----------------------------------|--------|---------------------------------|-----------|
| | 2011 | 2010 | 2011 | 2010 |
| Unrealized foreign exchange gain (loss) | \$783 | \$97 | \$621 | \$181 |
| Realized foreign exchange gain (loss) | \$(529 |)\$(61 |)\$(91 |)\$(652) |

(13) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

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

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

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

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

Recurring Fair Value Measures

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.

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

| | As of September 30, 2011 | | | Counterparty Netting | Cash Collateral | Total |
|---|--------------------------|------------------|----------------|-------------------------|--------------------|------------------|
| | Level 1 | Level 2 | Level 3 | | | |
| Assets: | | | | | | |
| Commodity derivatives — Energy Marketing | \$— | \$370,586 | \$9,193 | \$(325,992) | \$(3,268) | \$50,519 |
| Commodity derivatives — Oil and Gas | — | 11,740 | 328 | — | — | 12,068 |
| Commodity derivatives — Regulated Utilities Group | — | (8,703) | — | — | 12,058 | 3,355 |
| Money market funds | 9,006 | — | — | — | — | 9,006 |
| Total | \$9,006 | \$373,623 | \$9,521 | \$(325,992) | \$8,790 | \$74,948 |
| Liabilities: | | | | | | |
| Commodity derivatives — Energy Marketing | \$— | \$365,646 | \$4,619 | \$(325,992) | \$(12,294) | \$31,979 |
| Commodity derivatives — Oil and Gas | — | 7 | — | — | — | 7 |
| Commodity derivatives — Regulated Utilities Group | — | 1,360 | — | — | — | 1,360 |
| Foreign currency derivatives | — | — | — | — | — | — |
| Interest rate swaps | — | 122,420 | — | — | — | 122,420 |
| Total | \$— | \$489,433 | \$4,619 | \$(325,992) | \$(12,294) | \$155,766 |
| As of December 31, 2010 | | | | | | |
| | Level 1 | Level 2 | Level 3 | Counterparty Netting | Cash Collateral | Total |
| Assets: | | | | | | |
| Commodity derivatives — Energy Marketing | \$— | \$166,405 | \$7,976 | \$(122,639) | \$(1,410) | \$50,332 |
| Commodity derivatives — Oil and Gas | — | 10,281 | 266 | — | — | 10,547 |
| Commodity derivatives — Regulated Utilities Group | — | (5,568) | — | — | 10,355 | 4,787 |
| Money market funds | 8,050 | — | — | — | — | 8,050 |
| Foreign currency derivatives | — | 166 | — | — | — | 166 |
| Total | \$8,050 | \$171,284 | \$8,242 | \$(122,639) | \$8,945 | \$73,882 |
| Liabilities: | | | | | | |
| Commodity derivatives — Energy Marketing | \$— | \$143,537 | \$2,463 | \$(122,639) | \$(5,368) | \$17,993 |
| Commodity derivatives — Oil and Gas | — | 5,115 | — | — | — | 5,115 |
| Commodity derivatives — Regulated Utilities Group | — | 1,620 | — | — | — | 1,620 |
| Foreign currency derivatives | — | 21 | — | — | — | 21 |
| Interest rate swaps | — | 75,779 | — | — | — | 75,779 |
| Total | \$— | \$226,072 | \$2,463 | \$(122,639) | \$(5,368) | \$100,528 |

| | As of September 30, 2010 | | | | | |
|--|--------------------------|------------------|----------------|-------------------------|--------------------|------------------|
| | Level 1 | Level 2 | Level 3 | Counterparty Netting | Cash Collateral | Total |
| Assets: | | | | | | |
| Commodity derivatives — Energy Marketing | \$— | \$221,740 | \$3,246 | \$(154,306) | \$(7,387) | \$63,293 |
| Commodity derivatives — Oil and Gas | — | 13,459 | 562 | — | — | 14,021 |
| Commodity derivatives — Regulated Utilities Group | — | (13,382) | — | — | 20,518 | 7,136 |
| Money market funds | 10,050 | — | — | — | — | 10,050 |
| Foreign currency derivatives | — | — | — | — | — | — |
| Total | \$10,050 | \$221,817 | \$3,808 | \$(154,306) | \$13,131 | \$94,500 |
| Liabilities: | | | | | | |
| Commodity derivatives — Energy Marketing | \$— | \$172,401 | \$840 | \$(154,305) | \$(22) | \$18,914 |
| Commodity derivatives — Oil and Gas | — | 3,720 | — | — | — | 3,720 |
| Commodity derivatives — Regulated Utilities Group | — | 2,696 | — | — | — | 2,696 |
| Foreign currency derivatives | — | 11 | — | — | — | 11 |
| Interest rate swaps | — | 108,869 | — | — | — | 108,869 |
| Total | \$— | \$287,697 | \$840 | \$(154,305) | \$(22) | \$134,210 |

The following tables present the changes in level 3 recurring fair value for the three and nine months ended September 30, 2011 and 2010, respectively (in thousands):

| | Three Months Ended September 30, 2011 Commodity Derivatives | Nine Months Ended September 30, 2011 Commodity Derivatives |
|--|--|---|
| Balance as of beginning of period | \$6,427 | \$5,779 |
| Unrealized losses | (4,359) | (6,981) |
| Unrealized gains | 2,317 | 7,870 |
| Purchases | — | — |
| Issuances | — | — |
| Settlements | 197 | (1,761) |
| Transfers into level 3 ^(a) | 254 | — |
| Transfers out of level 3 ^(b) | 66 | (5) |
| Balances at end of period | \$4,902 | \$4,902 |
| Changes in unrealized gains relating to instruments still held as of period-end | \$1,067 | \$1,307 |

| | Three Months Ended September 30, 2010 | Nine Months Ended September 30, 2010 | |
|--|--|---|---|
| | Commodity Derivatives | Commodity Derivatives | |
| Balance as of beginning of period | \$2,176 | \$(556 |) |
| Unrealized losses | 961 | (1,206 |) |
| Unrealized gains | 850 | 4,576 | |
| Settlements | (365 |) (1,170 |) |
| Transfers into level 3 ^(a) | (62 |) (78 |) |
| Transfers out of level 3 ^(b) | (592 |) 1,402 | |
| Balances at end of period | \$2,968 | \$2,968 | |
| Changes in unrealized losses relating to instruments still held as of period-end | \$(528 |) \$1,283 | |

(a) Transfers into level 3 represent assets and liabilities that were previously categorized as a higher level for which the inputs became unobservable.

(b) Transfers out of level 3 represent assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

Realized and unrealized gains (losses) for level 3 commodity derivatives totaling \$(1.7) million and \$1.3 million for the three and nine months ended September 30, 2011, respectively, are included in Operating revenue on the accompanying Condensed Consolidated Statements of Income while \$(0.3) million and \$(0.4) million was recorded through Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets for the three and nine months ended September 30, 2011, respectively. Commodity derivatives classified as level 3 may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter.

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions. Further, the amounts do not include net cash collateral of \$21.1 million, \$14.3 million and \$13.2 million on deposit in margin accounts at September 30, 2011, December 31, 2010, and September 30, 2010, respectively, to collateralize certain financial instruments, which are included in Derivative assets - current, Derivative assets - non-current, Derivative liabilities - current and/or Derivative liabilities - non-current. Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 12.

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

As of September 30, 2011

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--------------------------------------|---------------------------------|-------------------------------------|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 198 | \$ 2 |
| Commodity derivatives | Derivative assets — non-current | — | — |
| Commodity derivatives | Derivative liabilities — current | 2,474 | 738 |
| Commodity derivatives | Derivative liabilities — non-current | — | — |
| Interest rate swaps | Derivative liabilities — current | — | 6,724 |
| Interest rate swaps | Derivative liabilities — non-current | — | 21,108 |
| Total derivatives designated as hedges | | \$2,672 | \$28,572 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$54,747 | \$17,996 |
| Commodity derivatives | Derivative assets — non-current | 19,890 | 2,675 |
| Commodity derivatives | Derivative liabilities — current | 344,799 | 384,729 |
| Commodity derivatives | Derivative liabilities — non-current | 44,799 | 49,255 |
| Foreign currency derivatives | Derivative liabilities — current | — | — |
| Interest rate swaps | Derivative liabilities — current | — | 94,588 |
| Total derivatives not designated as hedges | | \$464,235 | \$549,243 |

As of December 31, 2010

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--------------------------------------|---------------------------------|-------------------------------------|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 10,952 | \$1,452 |
| Commodity derivatives | Derivative assets — non-current | 48 | 71 |
| Commodity derivatives | Derivative liabilities — current | — | 45 |
| Commodity derivatives | Derivative liabilities — non-current | — | — |
| Interest rate swaps | Derivative liabilities — current | — | 6,823 |
| Interest rate swaps | Derivative liabilities — non-current | — | 14,976 |
| Total derivatives designated as hedges | | \$ 11,000 | \$23,367 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$ 149,936 | \$113,364 |
| Commodity derivatives | Derivative assets — non-current | 12,382 | 3,099 |
| Commodity derivatives | Derivative liabilities — current | 20,588 | 42,865 |
| Commodity derivatives | Derivative liabilities — non-current | 978 | 7,363 |
| Foreign currency derivatives | Derivative assets — current | 166 | 21 |
| Interest rate swaps | Derivative liabilities — current | — | 53,980 |
| Total derivatives not designated as hedges | | \$ 184,050 | \$220,692 |

As of September 30, 2010

| | Balance Sheet Location | Fair Value of Asset Derivatives | Fair Value of Liability Derivatives |
|--|--------------------------------------|---------------------------------------|---|
| Derivatives designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$20,387 | \$1,329 |
| Commodity derivatives | Derivative assets — non-current | 11 | — |
| Commodity derivatives | Derivative liabilities — current | — | 219 |
| Commodity derivatives | Derivative liabilities — non-current | — | 3 |
| Interest rate swaps | Derivative liabilities — current | — | 6,901 |
| Interest rate swaps | Derivative liabilities — non-current | — | 21,519 |
| Total derivatives designated as hedges | | \$20,398 | \$29,971 |
| Derivatives not designated as hedges: | | | |
| Commodity derivatives | Derivative assets — current | \$193,431 | \$154,470 |
| Commodity derivatives | Derivative assets — non-current | 22,321 | 9,032 |
| Commodity derivatives | Derivative liabilities — current | 15,944 | 36,703 |
| Commodity derivatives | Derivative liabilities — non-current | 2,460 | 6,830 |
| Interest rate swaps | Derivative liabilities — current | — | 80,450 |
| Interest rate swaps | Derivative liabilities — non-current | — | — |
| Foreign currency derivatives | Derivative asset — current | — | 11 |
| Foreign currency derivatives | Derivative liabilities — current | — | — |
| Total derivatives not designated as hedges | | \$234,156 | \$287,496 |

Our derivative activities are discussed in Note 12. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2011.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged items on our accompanying Condensed Consolidated Statements of Income was as follows (in thousands):

| Derivatives in Fair Value Hedging Relationships | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2011 |
|---|---|---|---|
| | | Amount of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income |
| Commodity derivatives | Operating revenue | \$1,235 | \$(7,502) |
| Fair value adjustment for natural gas inventory designated as the hedged item | Operating revenue | (1,100) | 7,379 |
| | | \$135 | \$(123) |
| | | Three Months Ended September 30, 2010 | Nine Months Ended September 30, 2010 |
| Derivatives | | | |

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| in Fair Value Hedging Relationships | Location of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income |
|---|---|---|---|
| Commodity derivatives | Operating revenue | \$ 10,421 | \$ 18,430 |
| Fair value adjustment for natural gas inventory designated as the hedged item | Operating revenue | (10,247 |) (18,425) |
| | | \$ 174 | \$ 5 |

Cash Flow Hedges

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

Three Months Ended September 30, 2011

| Derivatives in Cash Flow Hedging Relationships | Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion) | Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) | Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion) | Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) | Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) |
|--|---|--|--|--|--|
| Interest rate swaps | \$ (6,958 |) Interest expense | \$ (1,930 |) | \$— |
| Commodity derivatives | 10,095 | Operating revenue | 1,516 | Operating revenue | — |
| Total | \$ 3,137 | | \$ (414 |) | \$— |

Three Months Ended September 30, 2010

| 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 | \$ 30,227 | Interest expense | \$ (1,859 |) | \$— |
| Commodity derivatives | (24,912 |) Operating revenue | 14,540 | Operating revenue | (134 |
| Total | \$ 5,315 | | \$ 12,681 | |) \$(134 |

Nine Months Ended September 30, 2011

| Derivatives in Cash Flow Hedging Relationships | Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion) | Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) | Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion) | Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) | Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) |
|--|---|--|--|--|--|
| Interest rate swaps | \$ (11,428 |) Interest expense | \$ (5,741 |) | \$— |
| Commodity derivatives | 9,784 | Operating revenue | 2,849 | Operating revenue | — |
| Total | \$ (1,644 |) | \$ (2,892 |) | \$— |

Nine Months Ended September 30, 2010

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

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| | (Effective Portion) | (Effective Portion) | (Effective Portion) | (Ineffective Portion) | (Ineffective Portion) |
|--------------------------|------------------------|------------------------|------------------------|--------------------------|--------------------------|
| Interest rate swaps | \$ 18,341 | Interest expense | \$(5,683 |) | \$— |
| Commodity derivatives | (18,822 |) Operating revenue | 12,592 | Operating revenue | (451) |
| Total | \$(481 |) | \$6,909 | | \$(451) |

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Derivatives Not Designated as Hedge Instruments

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

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended | Nine Months Ended |
|---|---|---|---|
| | | September 30, 2011 | September 30, 2011 |
| | | Amount of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income |
| Commodity derivatives | Operating revenue | \$(18,529 |) \$(14,321) |
| Interest rate swaps - unrealized | Interest rate swaps — unrealized (loss) gain | (38,246 |) (40,608) |
| Interest rate swaps - realized | Interest expense | (3,373 |) (10,077) |
| Foreign currency contracts | Operating revenue | — | (143) |
| | | \$(60,148 |) \$(65,149) |

| Derivatives Not Designated as Hedging Instruments | Location of Gain/(Loss) on Derivatives Recognized in Income | Three Months Ended | Nine Months Ended |
|---|---|---|---|
| | | September 30, 2010 | September 30, 2010 |
| | | Amount of Gain/(Loss) on Derivatives Recognized in Income | Amount of Gain/(Loss) on Derivatives Recognized in Income |
| Commodity derivatives | Operating revenue | \$9,589 | \$13,798 |
| Interest rate swaps - unrealized | Interest rate swaps — unrealized (loss) gain | (13,710 |) (41,663) |
| Interest rate swaps - realized | Interest expense | (3,773 |) (9,953) |
| Foreign currency contracts | Operating revenue | 3 | (12) |
| | | \$(7,891 |) \$(37,830) |

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments was as follows (in thousands):

| | September 30, 2011 | | December 31, 2010 | | September 30, 2010 | |
|--|--------------------|-------------|-------------------|-------------|--------------------|-------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | \$74,779 | \$74,779 | \$32,438 | \$32,438 | \$58,975 | \$58,975 |
| Restricted cash | \$4,080 | \$4,080 | \$4,260 | \$4,260 | \$17,082 | \$17,082 |
| Derivative financial instruments - assets | \$65,942 | \$65,942 | \$65,832 | \$65,832 | \$84,450 | \$84,450 |
| Derivative financial instruments - liabilities | \$155,766 | \$155,766 | \$100,528 | \$100,528 | \$134,210 | \$134,210 |
| Notes payable | \$359,000 | \$359,000 | \$249,000 | \$249,000 | \$145,000 | \$145,000 |
| Long-term debt, including current maturities | \$1,285,087 | \$1,430,271 | \$1,191,231 | \$1,290,519 | \$1,193,607 | \$1,303,338 |

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

Cash, Cash Equivalents

The carrying amount approximates fair value due to the short maturity of these instruments.

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Restricted Cash

The carrying amounts of our restricted cash approximate fair value due to the short maturity of these instruments.

Restricted cash is primarily related to cash held in escrow required by Black Hills Wyoming project financing agreements. These funds are held in 30-day guaranteed investment certificates of \$1.2 million, \$3.6 million and \$10.6 million for September 30, 2011, December 31, 2010 and September 30, 2010, respectively.

At September 30, 2010, \$6.2 million was held at our Oil and Gas segment in accordance with terms of a settlement.

Derivative Financial Instruments

Derivative financial instruments are carried at fair value. Our fair value measurements are developed using a variety of inputs by our risk management group, which is independent of the trading function. These inputs include unadjusted quoted prices where available; prices published by various third-party providers; and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Some of our transactions take place in markets with limited liquidity and limited price visibility. Additionally, descriptions of the various instruments we use and the valuation method employed are included in Notes 12 and 13.

Notes Payable

The carrying amount approximates fair value due to the variable interest rates with short reset periods.

Long-Term Debt

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits if we were to call these bonds.

(15) COMMITMENTS AND CONTINGENCIES

Legal Proceedings

We are subject to various legal proceedings, claims and litigation as described in Note 19 of the Notes to our Consolidated Financial Statements in our 2010 Annual Report on Form 10-K. There are no material proceedings that have developed, no material developments with respect to existing legal proceedings and no material proceedings have terminated during the first nine months of 2011.

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of September 30, 2011 cannot be reasonably determined and could have a material effect on our results of operations or financial position.

Other Commitments

Construction of a 180 MW power generation facility by our Colorado Electric utility and a 200 MW power generation facility by our Power Generation segment is progressing. Total cost of construction is expected to be approximately \$227.0 million for Colorado Electric and approximately \$260.0 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. We have procured contracts for the turbines, building construction and labor. As of September 30, 2011, we have committed contracts for 100% of the construction for the Colorado Electric utility and 100% of the construction for the Power Generation segment.

PPA Extension

In June 2011, FERC approved an extension of the PPA between Black Hills Wyoming and Cheyenne Light which was due to expire in August 2011. This agreement, now extended through August 2014, provides energy and capacity to Cheyenne Light from Black Hills Wyoming's Gillette CT.

(16) GUARANTEES

We had provided a guarantee for up to \$7.0 million of Enserco's obligations under an agency agreement. During the first quarter of 2011, the guarantee expired upon fulfillment of all obligations under the contract.

The construction of the office building in Papillion, Nebraska was completed and the guarantee for \$6.0 million was terminated upon purchase of the building on April 1, 2011.

In June 2011, a guarantee to Colorado Interstate Gas was amended. It was amended to increase the guarantee amount to \$10.0 million and extend the expiration date to July 31, 2012. All other terms remained the same.

In June 2011, we issued a guarantee to Cross Timbers Energy Services for the performance and payment obligations of Black Hills Utility Holdings for natural gas supply purchases up to \$7.5 million. The guarantee expires on June 30, 2012 or upon 30 days written notice to the counterparty.

In July 2011, we issued a \$33.3 million guarantee to Vestas-American Wind Technology, Inc. for the performance and payment obligations of Colorado Electric relating to the purchase of wind turbines for a Colorado Electric wind power generation project. This guarantee will remain in effect until satisfaction of Colorado Electric's contractual obligations. We expect the guarantee to expire on or about January 15, 2013.

(17) SUBSEQUENT EVENT

Equity Forward Instrument

On November 1, 2011, we settled the equity forward agreements by physically delivering 4,413,519 shares of common stock and we received cash proceeds of approximately \$120 million. The price used to determine cash proceeds was calculated based on the November 2010 public offering price of our common stock, adjusted for underwriting fees, as well as a daily adjustment based on the federal funds rate less a spread, and a decrease to reflect the dividend paid on our common stock subsequent to November 10, 2010.

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

We are a diversified 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 reportable operating segments:

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

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities generate, transmit and distribute electricity to approximately 201,000 customers in South Dakota, Wyoming, Colorado and Montana. In addition, Cheyenne Light, which is also reported within the Electric Utilities segment, provides natural gas to approximately 34,500 customers in Wyoming. Our Gas Utilities serve approximately 527,000 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power from our generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil, coal, power, environmental products and related services in the United States and Canada.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for gas utilities is November through March, and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2011, and our financial condition as of September 30, 2011, December 31, 2010, and September 30, 2010 are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 70.

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.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net loss for the three months ended September 30, 2011 was \$10.5 million, or \$0.27 per share, compared to Net income of \$12.4 million, or \$0.32 per share, reported for the same period in 2010. The 2011 Net loss included a \$24.9 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2010 Net income included an \$8.9 million

after-tax unrealized mark-to-market loss on these same interest rate swaps, a \$4.1 million after-tax gain on the sale of a 23% ownership interest in Wygen III and a \$2.4 million favorable tax adjustment for a re-measurement of certain tax positions.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the nine months ended September 30, 2011 was \$24.1 million, or \$0.61 per share, compared to \$35.2 million, or \$0.90 per share, reported for the same period in 2010. The 2011 Net income included a \$26.4 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2010 Net income included a \$27.1 million after-tax mark-to-market unrealized loss on these same interest rate swaps, a \$5.8 million after-tax gain on the sale of assets of Nebraska Gas and of a 23% ownership interest in Wygen III and a \$2.4 million favorable tax adjustment for a re-measurement of certain tax positions.

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|----------------------------|-------------------------------------|-----------|------------------------|------------------------------------|-----------|------------------------|
| | 2011 | 2010 | Increase (Decrease) | 2011 | 2010 | Increase (Decrease) |
| | (in thousands) | | | | | |
| Operating revenue * | | | | | | |
| Utilities | \$226,367 | \$213,968 | \$12,399 | \$844,365 | \$829,327 | \$15,038 |
| Non-regulated Energy | 52,036 | 50,459 | 1,577 | 150,156 | 151,303 | (1,147) |
| Intercompany eliminations | (21,943) | (14,933) | (7,010) | (61,636) | (48,298) | (13,338) |
| | \$256,460 | \$249,494 | \$6,966 | \$932,885 | \$932,332 | \$553 |
| Net income (loss) | | | | | | |
| Electric Utilities | \$15,790 | \$18,537 | \$(2,747) | \$34,653 | \$35,585 | \$(932) |
| Gas Utilities | 572 | (595) |)1,167 | 24,275 | 18,017 | 6,258 |
| Utilities | 16,362 | 17,942 | (1,580) | 58,928 | 53,602 | 5,326 |
| Oil and Gas | 241 | 836 | (595) | (553) |)3,405 | (3,958) |
| Power Generation | 337 | 575 | (238) | 2,071 | 1,239 | 832 |
| Coal Mining | 555 | 1,673 | (1,118) | (1,124) |)6,093 | (7,217) |
| Energy Marketing | 273 | 1,370 | (1,097) | 1,327 | 4,890 | (3,563) |
| Non-regulated Energy | 1,406 | 4,454 | (3,048) | 1,721 | 15,627 | (13,906) |
| Corporate | (27,943) | (10,093) | (17,850) | (36,101) | (34,221) | (1,880) |
| Inter-company eliminations | (350) |)87 | (437) | (411) |)157 | (568) |
| | \$(10,525) |)\$12,390 | \$(22,915) | \$24,137 | \$35,165 | \$(11,028) |

2010 Operating revenue has been restated to eliminate certain inter-company revenue previously not eliminated.

*This change did not have an impact on our gross margin or net income. See Note 1 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Business Group highlights for 2011 include:

Utilities Group

Our return on investments made in the utilities was positively impacted by new and interim rates and tariffs implemented in five utility jurisdictions during 2010 and early 2011. Consequently, year-to-date revenues have been positively impacted for rates that were not in effect in the prior periods.

| Utility | State | Effective Date | Annual Revenue Increase (in millions) |
|-------------------|-------|----------------|---------------------------------------|
| Black Hills Power | SD | 4/2010 | \$ 15.2 |
| Black Hills Power | SD | 6/2010 | \$ 3.1 |
| Colorado Electric | CO | 8/2010 | \$ 17.9 |
| Nebraska Gas | NE | 3/2010 | \$ 8.3 |
| Iowa Gas | IA | 6/2010 | \$ 3.4 |
| | | | \$ 47.9 |

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Construction of gas-fired generation to serve Colorado Electric customers is continuing to progress and is on schedule to begin providing energy on or before January 1, 2012. The 180 MW generation project is expected to cost approximately \$227 million, of which \$222 million has been expended through September 30, 2011.

On April 28, 2011, Colorado Electric filed a request with the CPUC for a revenue increase of \$40.2 million to recover costs and a return associated with the 180 MW generation project and other utility infrastructure assets and expenses, including PPA costs associated with the 200 MW Colorado IPP generation facility. The proposed rate increase would go into effect on January 1, 2012 to coincide with the expiration of the PPA with PSCo. Colorado Electric's Rebuttal Testimony was filed on October 14, 2011 and a hearing on the rate case with the CPUC began on November 1, 2011.

On August 12, 2011, Colorado Electric received approval from the CPUC to rate base 50% ownership in a 29 MW wind turbine project as part of its plan to meet Colorado's Renewable Energy Standard. The CPUC authorized us to conduct a competitive solicitation for ownership of the other 50% of the project. Colorado Electric's share of this project is expected to cost approximately \$26.5 million and is expected to begin serving Colorado Electric customers no later than December 31, 2012.

On March 14, 2011, Colorado Electric filed a request for a CPCN to construct a third utility-owned 88 MW natural gas-fired turbine with an approximate cost of \$102.0 million, excluding transmission. This CPCN request was filed in accordance with a December 2010 CPUC order. This order approved the retirement of the W.N. Clark coal-fired power plant under the Colorado Clean Air-Clean Jobs Act and granted a presumption of need for a portion of a third turbine. An initial settlement with interveners was reached and a settlement hearing occurred on October 25, 2011. Under the proposed settlement, Colorado Electric will construct the plant and own 42 MW and will sell the remaining 46 MW to a buyer who will provide a seven-year capacity purchase agreement. The capacity purchase agreement would require Colorado Electric to purchase the 46 MW ownership interest after contract expiration. An initial decision is expected by December 1, 2011.

On November 1, 2011, Cheyenne Light filed a motion to rescind its filing for a certificate of public convenience and necessity with the WPSC to construct and operate a \$158 million, 120 MW electric generation facility. This original filing was replaced with a new joint request filed on November 1, 2011 by Cheyenne Light and Black Hills Power with the WPSC for a certificate of public convenience and necessity to construct and operate a new \$237 million natural gas-fired electric generation facility and related gas and electric transmission in Cheyenne, Wyo. The proposed facility will include construction of one simple-cycle, 37 MW combustion turbine that will be wholly owned by Cheyenne Light and one combined-cycle, 95 MW unit that will be jointly owned by Cheyenne Light and Black Hills Power. Cheyenne Light will own 40 MW and Black Hills Power will own 55 MW of the combined cycle unit.

On June 13, 2011, the SDPUC dismissed Black Hills Power's request for declaratory ruling to confirm that a proposed 20 MW wind farm site near Belle Fourche, SD is reasonable and cost effective.

In June 2011, the SDPUC approved an Environmental Improvement Adjustment tariff for Black Hills Power. The Environmental Improvement Adjustment, which was implemented to recover Black Hill Power's investment of \$25 million for pollution control equipment at the PacifiCorp-operated Wyodak plant, went into effect on June 1, 2011 with an annual revenue increase of \$3.1 million.

Non-regulated Energy Group

Construction of gas-fired generation by Colorado IPP to serve a 20-year PPA with Colorado Electric is continuing to progress and is on schedule to begin providing energy on January 1, 2012. The 200 MW project is expected to cost approximately \$260 million, of which \$250 million has been expended through September 30, 2011.

In January 2011, we sold our ownership interests in the partnerships that owned the Idaho generating facilities for \$0.8 million and recorded a gain of \$0.8 million.

Corporate

We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of \$40.6 million for the nine months ended September 30, 2011 compared to a \$41.7 million unrealized mark-to-market loss on these swaps for the same period in 2010.

On November 1, 2011, the Equity Forward Agreements were settled by issuing 4,413,519 shares of Black Hills Corporation common stock in return for net cash proceeds of approximately \$120 million.

In September 2011, we extended our \$100 million term loan under the existing terms for two-years.

In June 2011, we entered into a \$150 million one year, unsecured, single draw, term loan. The cost of borrowing under this term loan is based on a spread of 125 basis points over LIBOR. The proceeds were used to pay down a portion of our Revolving Credit Facility.

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, Nebraska, Iowa and Kansas.

Electric Utilities

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|-------------------------------------|-------------------------------------|-----------|------------------------------------|-----------|
| | 2011 | 2010 | 2011 | 2010 |
| | (in thousands) | | | |
| Revenue — electric | \$149,664 | \$138,122 | \$417,512 | \$399,298 |
| Revenue — gas | 4,052 | 3,523 | 24,014 | 27,421 |
| Total revenue | 153,716 | 141,645 | 441,526 | 426,719 |
| Fuel and purchased power — electric | 71,387 | 67,104 | 203,319 | 205,409 |
| Purchased gas | 1,703 | 1,157 | 13,583 | 16,929 |
| Total fuel and purchased power | 73,090 | 68,261 | 216,902 | 222,338 |
| Gross margin — electric | 78,277 | 71,018 | 214,193 | 193,889 |
| Gross margin — gas | 2,349 | 2,366 | 10,431 | 10,492 |
| Total gross margin | 80,626 | 73,384 | 224,624 | 204,381 |
| Operations and maintenance | 34,837 | 33,428 | 106,107 | 102,152 |
| Gain on sale of operating assets | (768 |) (6,238 |) (768 |) (6,238 |
| Depreciation and amortization | 13,221 | 12,481 | 39,051 | 35,567 |
| Total operating expenses | 47,290 | 39,671 | 144,390 | 131,481 |
| Operating income | 33,336 | 33,713 | 80,234 | 72,900 |

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| | | | | | |
|-----------------------------|----------|-----------|-----------|-----------|---|
| Interest expense, net | (9,729 |) (10,573 |) (29,780 |) (27,275 |) |
| Other income (expense), net | 200 | 400 | 556 | 2,840 | |
| Income tax expense | (8,017 |) (5,003 |) (16,357 |) (12,880 |) |
| Net income | \$15,790 | \$18,537 | \$34,653 | \$35,585 | |

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

| Revenue - electric (in thousands) | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|-----------------------------------|-------------------------------------|------------------|------------------------------------|------------------|
| | 2011 | 2010 | 2011 | 2010 |
| Residential: | | | | |
| Black Hills Power | \$15,034 | \$13,492 | \$44,977 | \$39,517 |
| Cheyenne Light | 7,826 | 7,235 | 22,923 | 21,945 |
| Colorado Electric | 24,462 | 21,674 | 64,053 | 57,697 |
| Total Residential | 47,322 | 42,401 | 131,953 | 119,159 |
| Commercial: | | | | |
| Black Hills Power | 19,889 | 18,529 | 54,962 | 49,172 |
| Cheyenne Light | 14,802 | 14,379 | 40,840 | 40,251 |
| Colorado Electric | 19,784 | 17,833 | 54,742 | 49,528 |
| Total Commercial | 54,475 | 50,741 | 150,544 | 138,951 |
| Industrial: | | | | |
| Black Hills Power | 6,716 | 5,402 | 18,944 | 16,243 |
| Cheyenne Light | 3,017 | 2,156 | 8,573 | 7,568 |
| Colorado Electric | 8,086 | 7,606 | 24,520 | 21,391 |
| Total Industrial | 17,819 | 15,164 | 52,037 | 45,202 |
| Municipal: | | | | |
| Black Hills Power | 908 | 850 | 2,425 | 2,251 |
| Cheyenne Light | 475 | 419 | 1,321 | 887 |
| Colorado Electric | 3,442 | 3,130 | 9,564 | 7,688 |
| Total Municipal | 4,825 | 4,399 | 13,310 | 10,826 |
| Contract Wholesale: | | | | |
| Black Hills Power | 4,519 | 4,758 | 13,509 | 18,554 |
| Off-system Wholesale: | | | | |
| Black Hills Power | 9,158 | 9,695 | 23,553 | 26,950 |
| Cheyenne Light | 1,535 | 2,545 | 7,002 | 7,255 |
| Colorado Electric ^(a) | — | 506 | — | 10,742 |
| Total Off-system Wholesale | 10,693 | 12,746 | 30,555 | 44,947 |
| Other: | | | | |
| Black Hills Power | 8,716 | 6,325 | 21,862 | 17,291 |
| Cheyenne Light | 649 | 773 | 1,905 | 2,474 |
| Colorado Electric | 646 | 815 | 1,837 | 1,894 |
| Total Other | 10,011 | 7,913 | 25,604 | 21,659 |
| Total Revenue - electric | \$149,664 | \$138,122 | \$417,512 | \$399,298 |

(a) In August 2010, Colorado Electric agreed with the CPUC to defer off-system operating income until a sharing mechanism is settled upon. As a result Colorado Electric deferred \$2.0 million and \$8.4 million in off-system revenue during the three and nine months ended September 30, 2011, respectively, and \$2.1 million commencing August 6, 2010 for the three and nine months ended September 30, 2010.

| Quantities Generated and Purchased (in MWh) | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|-------------------------------------|-----------|------------------------------------|-----------|
| | 2011 | 2010 | 2011 | 2010 |
| Generated — | | | | |
| Coal-fired: | | | | |
| Black Hills Power | 463,032 | 525,000 | 1,286,876 | 1,514,831 |
| Cheyenne Light | 170,643 | 196,079 | 511,209 | 553,978 |
| Colorado Electric | 74,470 | 66,951 | 202,381 | 193,195 |
| Total Coal | 708,145 | 788,030 | 2,000,466 | 2,262,004 |
| Gas and Oil-fired: | | | | |
| Black Hills Power | 11,424 | 11,780 | 13,595 | 15,724 |
| Cheyenne Light | — | — | — | — |
| Colorado Electric | 2,748 | 1,061 | 2,778 | 1,154 |
| Total Gas and Oil-fired | 14,172 | 12,841 | 16,373 | 16,878 |
| Total Generated: | | | | |
| Black Hills Power | 474,456 | 536,780 | 1,300,471 | 1,530,555 |
| Cheyenne Light | 170,643 | 196,079 | 511,209 | 553,978 |
| Colorado Electric | 77,218 | 68,012 | 205,159 | 194,349 |
| Total Generated | 722,317 | 800,871 | 2,016,839 | 2,278,882 |
| Purchased — | | | | |
| Black Hills Power | 409,174 | 314,924 | 1,186,004 | 1,035,124 |
| Cheyenne Light | 172,520 | 166,082 | 548,768 | 510,509 |
| Colorado Electric | 527,975 | 540,192 | 1,496,812 | 1,569,350 |
| Total Purchased | 1,109,669 | 1,021,198 | 3,231,584 | 3,114,983 |
| Total Generated and Purchased: | | | | |
| Black Hills Power | 883,630 | 851,704 | 2,486,475 | 2,565,679 |
| Cheyenne Light | 343,163 | 362,161 | 1,059,977 | 1,064,487 |
| Colorado Electric | 605,193 | 608,204 | 1,701,971 | 1,763,699 |
| Total Generated and Purchased | 1,831,986 | 1,822,069 | 5,248,423 | 5,393,865 |

| Quantity Sold (in MWh) | Three Months Ended | | Nine Months Ended | |
|----------------------------------|-----------------------|-----------|-----------------------|-----------|
| | September 30, 2011 | 2010 | September 30, 2011 | 2010 |
| Residential: | | | | |
| Black Hills Power | 132,571 | 122,123 | 414,654 | 410,561 |
| Cheyenne Light | 65,643 | 62,150 | 197,053 | 196,122 |
| Colorado Electric | 185,775 | 180,771 | 481,774 | 485,381 |
| Total Residential | 383,989 | 365,044 | 1,093,481 | 1,092,064 |
| Commercial: | | | | |
| Black Hills Power | 198,774 | 195,634 | 544,660 | 544,935 |
| Cheyenne Light | 157,138 | 160,359 | 446,382 | 449,483 |
| Colorado Electric | 201,266 | 201,989 | 547,168 | 554,584 |
| Total Commercial | 557,178 | 557,982 | 1,538,210 | 1,549,002 |
| Industrial: | | | | |
| Black Hills Power | 106,658 | 90,426 | 301,268 | 278,514 |
| Cheyenne Light | 44,857 | 32,943 | 128,327 | 117,373 |
| Colorado Electric | 90,895 | 95,795 | 265,992 | 265,789 |
| Total Industrial | 242,410 | 219,164 | 695,587 | 661,676 |
| Municipal: | | | | |
| Black Hills Power | 9,917 | 9,008 | 25,958 | 24,811 |
| Cheyenne Light | 2,528 | 2,223 | 7,122 | 3,836 |
| Colorado Electric | 36,657 | 36,465 | 96,483 | 85,881 |
| Total Municipal | 49,102 | 47,696 | 129,563 | 114,528 |
| Subtotal Retail Quantities Sold | 1,232,679 | 1,189,886 | 3,456,841 | 3,417,270 |
| Contract Wholesale: | | | | |
| Black Hills Power ^(a) | 84,346 | 83,013 | 256,558 | 371,736 |
| Off-system Wholesale: | | | | |
| Black Hills Power | 299,511 | 309,297 | 819,753 | 839,408 |
| Cheyenne Light | 47,615 | 86,675 | 211,541 | 234,937 |
| Colorado Electric ^(b) | 48,643 | 59,453 | 222,091 | 292,741 |
| Total Off-system Wholesale | 395,769 | 455,425 | 1,253,385 | 1,367,086 |
| Total Quantity Sold: | | | | |
| Black Hills Power | 831,777 | 809,501 | 2,362,851 | 2,469,965 |
| Cheyenne Light | 317,781 | 344,350 | 990,425 | 1,001,751 |
| Colorado Electric | 563,236 | 574,473 | 1,613,508 | 1,684,376 |
| Total Quantity Sold | 1,712,794 | 1,728,324 | 4,966,784 | 5,156,092 |
| Losses and Company Use: | | | | |
| Black Hills Power | 51,853 | 42,203 | 123,624 | 95,714 |
| Cheyenne Light | 25,382 | 17,811 | 69,552 | 62,736 |
| Colorado Electric | 41,957 | 33,731 | 88,463 | 79,323 |
| Total Losses and Company Use | 119,192 | 93,745 | 281,639 | 237,773 |

| | | | | |
|--------------|-----------|-----------|-----------|-----------|
| Total Energy | 1,831,986 | 1,822,069 | 5,248,423 | 5,393,865 |
|--------------|-----------|-----------|-----------|-----------|

(a) MWh for the nine months ended September 30, 2011 decreased due to the termination of a wholesale contract with a previous wholesale power customer that acquired ownership interest in the Wygen III facility.

(b) In August 2010, Colorado Electric agreed with the CPUC to defer off-system operating income until a sharing mechanism is determined. In accordance with this agreement, operating income for off-system MWh sold at Colorado Electric totaling \$0.2 million and \$0.4 million has been deferred for the three and nine months ended September 30, 2011 and \$0.5 million for the three and nine months ending September 30, 2010, respectively. Operating income of \$1.3 million has been deferred since the agreement was approved in August 2010.

| Degree Days | Three Months Ended September 30, 2011 | | 2010 | | | |
|--|---|----------------------------|------------------------------------|----------------------------|----|--|
| | Actual | Variance from Normal | Actual | Variance from Normal | | |
| Heating Degree Days: | | | | | | |
| Actual — | | | | | | |
| Black Hills Power | 153 | (33 |)% 188 | (17 |)% | |
| Cheyenne Light | 197 | (40 |)% 159 | (51 |)% | |
| Colorado Electric | 46 | (50 |)% 11 | (88 |)% | |
| Cooling Degree Days: | | | | | | |
| Actual — | | | | | | |
| Black Hills Power | 620 | 26 | % 456 | (8 |)% | |
| Cheyenne Light | 399 | 73 | % 310 | 34 | % | |
| Colorado Electric | 958 | 36 | % 793 | 13 | % | |
| Degree Days | Nine Months Ended September 30, 2011 | | 2010 | | | |
| Heating Degree Days: | Actual | Variance from Normal | Actual | Variance from Normal | | |
| Actual — | | | | | | |
| Black Hills Power | 5,050 | (30 |)% 4,484 | (3 |)% | |
| Cheyenne Light | 4,674 | (37 |)% 4,577 | (3 |)% | |
| Colorado Electric | 3,465 | (38 |)% 3,435 | 2 | % | |
| Cooling Degree Days: | | | | | | |
| Actual — | | | | | | |
| Black Hills Power | 676 | 13 | % 521 | (12 |)% | |
| Cheyenne Light | 429 | 57 | % 345 | 26 | % | |
| Colorado Electric | 1,252 | 36 | % 1,073 | 17 | % | |
| Electric Utilities Power Plant Availability | Three Months Ended September 30, | | Nine Months Ended September 30, | | | |
| | 2011 | 2010 | 2011 | 2010 | | |
| Coal-fired plants | 95.1 | % 95.9 | % 91.6 | % (a) 93.2 | % | |
| Other plants | 98.6 | % 98.5 | % 95.7 | % 98.5 | % | |
| Total availability | 96.4 | % 96.8 | % 93.1 | % 95.1 | % | |

(a) Reflects a major overhaul and an unplanned outage at the PacifiCorp-operated Wyodak plant.

Cheyenne Light Natural Gas Distribution

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

| | Three Months Ended | | Nine Months Ended | |
|------------------------------|--------------------|---------|-------------------|-----------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Revenue (in thousands): | | | | |
| Residential | \$2,561 | \$2,359 | \$14,592 | \$16,642 |
| Commercial | 946 | 736 | 6,492 | 7,791 |
| Industrial | 370 | 257 | 2,226 | 2,378 |
| Other | 175 | 171 | 704 | 610 |
| Total Revenue | \$4,052 | \$3,523 | \$24,014 | \$27,421 |
| Gross Margin (in thousands): | | | | |
| Residential | \$1,739 | \$1,779 | \$7,459 | \$7,329 |
| Commercial | 387 | 372 | 2,293 | 2,341 |
| Industrial | 63 | 49 | 338 | 276 |
| Other | 160 | 166 | 341 | 546 |
| Total Gross Margin | \$2,349 | \$2,366 | \$10,431 | \$10,492 |
| Volumes Sold (Dth): | | | | |
| Residential | 179,602 | 173,430 | 1,745,313 | 1,868,609 |
| Commercial | 122,138 | 111,643 | 1,048,404 | 1,104,484 |
| Industrial | 66,962 | 76,056 | 463,618 | 453,601 |
| Total Volumes Sold | 368,702 | 361,129 | 3,257,335 | 3,426,694 |

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Electric Utilities segment was \$15.8 million for the three months ended September 30, 2011 compared to \$18.5 million for the three months ended September 30, 2010 as a result of:

Gross margin increased \$7.2 million primarily due to \$2.5 million from rate adjustments that include a return on significant capital investments, \$1.7 million from an increase in retail volumes, \$2.0 million from transmission cost adjustments and \$0.6 million from the impact of a new Environmental Improvement Cost Recovery rider which went into effect on June 1, 2011, partially offset by lower off-system sales margins of \$0.3 million.

Operations and maintenance increased \$1.4 million primarily due to increased allocation of corporate costs resulting from higher asset deployment at the Electric Utilities and the impact of a decrease in property taxes in 2010 due to the settlement of appeals that resulted in an adjustment for prior years of \$0.4 million.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party and was eliminated in the consolidation. The gain on sale in 2010 represents the sale of a 23% ownership interest in the Wygen III generating facility.

Depreciation and amortization increased \$0.7 million primarily due to a higher asset bases.

Interest expense, net decreased \$0.8 million primarily due to higher AFUDC-borrowed associated with recent capital investments at Colorado Electric.

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

Income tax expense: The effective tax rate increased from the same period in the prior year primarily due to a \$2.2 million prior year tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit resulting from a rate case settlement in 2010.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Electric Utilities segment was \$34.7 million for the nine months ended September 30, 2011 compared to \$35.6 million for the nine months ended September 30, 2010 as a result of:

Gross margin increased \$20.2 million primarily due to \$17.1 million from rate adjustments that include a return on significant capital investments, \$5.3 million from transmission cost adjustments and \$0.6 million from the impact of a new Environmental Improvement Cost Recovery rider which went into effect on June 1, 2011, partially offset by lower off-system sales margins of \$2.6 million.

Operations and maintenance increased \$4.0 million primarily due to an increase in labor and employee benefit costs, increased allocation of corporate costs, additional costs associated with Wygen III, which commenced commercial operation on April 1, 2010, and an impact from lower property taxes in 2010 due to the settlement of appeals which resulted in an adjustment for prior years of \$0.4 million.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party and was eliminated in the consolidation. The gain on sale in 2010 represents the sale of a 23% ownership interest in the Wygen III generating facility.

Depreciation and amortization increased \$3.5 million primarily due to a higher asset base including additional depreciation associated with Wygen III, which commenced commercial operations on April 1, 2010.

Interest expense, net increased \$2.5 million primarily due to higher debt balances, partially offset by an increase in AFUDC-borrowed and interest income.

Other income (expense), net decreased \$2.3 million primarily due to decreased AFUDC-equity resulting from with the commencement of commercial operation of our Wygen III facility.

Income tax expense: The effective tax rate increased from the same period in the prior year primarily due to a \$2.2 million prior year tax benefit for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit resulting from a rate case settlement in 2010.

Gas Utilities

| | Three Months Ended September 30, 2011 | | 2010 | | Nine Months Ended September 30, 2011 | | 2010 | |
|----------------------------------|---|---|----------|---|--|---|-----------|---|
| | (in thousands) | | | | | | | |
| Revenue: | | | | | | | | |
| Natural gas — regulated | \$65,887 | | \$64,109 | | \$382,517 | | \$379,291 | |
| Other — non-regulated services | 6,764 | | 8,214 | | 20,322 | | 23,317 | |
| Total revenue | 72,651 | | 72,323 | | 402,839 | | 402,608 | |
| Cost of sales: | | | | | | | | |
| Natural gas — regulated | 29,693 | | 27,804 | | 229,152 | | 230,555 | |
| Other — non-regulated services | 3,480 | | 5,729 | | 10,260 | | 13,501 | |
| Total cost of sales | 33,173 | | 33,533 | | 239,412 | | 244,056 | |
| Gross margin | 39,478 | | 38,790 | | 163,427 | | 158,552 | |
| Operations and maintenance | 28,317 | | 26,957 | | 91,126 | | 93,406 | |
| Gain on sale of operating assets | — | | — | | — | | (2,683 |) |
| Depreciation and amortization | 6,064 | | 5,711 | | 18,032 | | 19,530 | |
| Total operating expenses | 34,381 | | 32,668 | | 109,158 | | 110,253 | |
| Operating income (loss) | 5,097 | | 6,122 | | 54,269 | | 48,299 | |
| Interest expense, net | (6,329 |) | (6,983 |) | (19,640 |) | (19,992 |) |
| Other income (expense), net | 27 | | (7 |) | 176 | | 42 | |
| Income tax benefit (expense) | 1,777 | | 273 | | (10,530 |) | (10,332 |) |
| Net income (loss) | \$572 | | \$(595 |) | \$24,275 | | \$18,017 | |

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

| Revenue (in thousands) | Three Months Ended | | Nine Months Ended | |
|--------------------------------|--------------------|----------|-------------------|-----------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Residential: | | | | |
| Colorado | \$5,493 | \$5,104 | \$39,228 | \$38,553 |
| Nebraska | 12,736 | 13,134 | 91,798 | 86,904 |
| Iowa | 11,235 | 11,239 | 77,259 | 74,814 |
| Kansas | 7,928 | 7,711 | 46,449 | 51,640 |
| Total Residential | 37,392 | 37,188 | 254,734 | 251,911 |
| Commercial: | | | | |
| Colorado | 1,352 | 1,156 | 8,167 | 8,384 |
| Nebraska | 3,520 | 3,441 | 29,823 | 30,101 |
| Iowa | 4,397 | 4,881 | 33,082 | 33,894 |
| Kansas | 2,076 | 2,048 | 14,316 | 16,352 |
| Total Commercial | 11,345 | 11,526 | 85,388 | 88,731 |
| Industrial: | | | | |
| Colorado | 1,174 | 920 | 1,872 | 1,213 |
| Nebraska | 194 | 441 | 530 | 2,582 |
| Iowa | 334 | 183 | 1,478 | 1,366 |
| Kansas | 10,437 | 8,831 | 18,406 | 13,166 |
| Total Industrial | 12,139 | 10,375 | 22,286 | 18,327 |
| Transportation: | | | | |
| Colorado | 84 | 95 | 591 | 546 |
| Nebraska | 1,626 | 1,735 | 8,057 | 8,308 |
| Iowa | 687 | 746 | 2,839 | 2,704 |
| Kansas | 1,311 | 1,222 | 4,503 | 4,206 |
| Total Transportation | 3,708 | 3,798 | 15,990 | 15,764 |
| Other: | | | | |
| Colorado | 22 | 22 | 78 | 78 |
| Nebraska | 432 | 396 | 1,551 | 1,492 |
| Iowa | 122 | 95 | 441 | 677 |
| Kansas | 727 | 709 | 2,049 | 2,311 |
| Total Other | 1,303 | 1,222 | 4,119 | 4,558 |
| Total Regulated | 65,887 | 64,109 | 382,517 | 379,291 |
| Other - non-regulated services | 6,764 | 8,214 | 20,322 | 23,317 |
| Total Revenue | \$72,651 | \$72,323 | \$402,839 | \$402,608 |

| Gross Margin (in thousands) | Three Months Ended | | Nine Months Ended | |
|--------------------------------|--------------------|----------|-------------------|-----------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Residential: | | | | |
| Colorado | \$2,695 | \$2,710 | \$12,575 | \$13,265 |
| Nebraska | 8,480 | 9,019 | 37,861 | 35,069 |
| Iowa | 8,291 | 8,053 | 34,885 | 32,128 |
| Kansas | 5,465 | 5,385 | 21,663 | 21,677 |
| Total Residential | 24,931 | 25,167 | 106,984 | 102,139 |
| Commercial: | | | | |
| Colorado | 460 | 462 | 2,105 | 2,372 |
| Nebraska | 1,486 | 1,542 | 8,462 | 8,720 |
| Iowa | 1,862 | 1,895 | 8,458 | 8,524 |
| Kansas | 1,006 | 991 | 4,731 | 4,771 |
| Total Commercial | 4,814 | 4,890 | 23,756 | 24,387 |
| Industrial: | | | | |
| Colorado | 239 | 218 | 402 | 309 |
| Nebraska | 48 | 60 | 139 | 294 |
| Iowa | 38 | 27 | 176 | 145 |
| Kansas | 1,144 | 976 | 2,136 | 1,639 |
| Total Industrial | 1,469 | 1,281 | 2,853 | 2,387 |
| Transportation: | | | | |
| Colorado | 84 | 95 | 590 | 546 |
| Nebraska | 1,626 | 1,735 | 8,057 | 8,308 |
| Iowa | 687 | 746 | 2,839 | 2,704 |
| Kansas | 1,311 | 1,222 | 4,503 | 4,219 |
| Total Transportation | 3,708 | 3,798 | 15,989 | 15,777 |
| Other: | | | | |
| Colorado | 22 | 22 | 78 | 78 |
| Nebraska | 433 | 396 | 1,552 | 1,491 |
| Iowa | 122 | 95 | 441 | 678 |
| Kansas | 695 | 656 | 1,712 | 1,799 |
| Total Other | 1,272 | 1,169 | 3,783 | 4,046 |
| Total Regulated | 36,194 | 36,305 | 153,365 | 148,736 |
| Other - non-regulated services | 3,284 | 2,485 | 10,062 | 9,816 |
| Total Gross Margin | \$39,478 | \$38,790 | \$163,427 | \$158,552 |

| Volumes Sold (in Dth) | Three Months Ended | | Nine Months Ended | |
|---------------------------|--------------------|-------------------|-------------------|-------------------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Residential: | | | | |
| Colorado | 450,778 | 415,476 | 4,298,162 | 4,386,492 |
| Nebraska | 764,676 | 795,150 | 8,607,301 | 8,515,902 |
| Iowa | 564,426 | 611,373 | 7,485,204 | 7,205,381 |
| Kansas | 461,169 | 430,282 | 4,710,725 | 4,835,615 |
| Total Residential | 2,241,049 | 2,252,281 | 25,101,392 | 24,943,390 |
| Commercial: | | | | |
| Colorado | 145,413 | 121,682 | 980,931 | 1,046,490 |
| Nebraska | 373,386 | 378,760 | 3,465,363 | 3,576,684 |
| Iowa | 486,758 | 568,192 | 4,375,492 | 4,275,759 |
| Kansas | 203,109 | 198,604 | 1,830,720 | 1,887,456 |
| Total Commercial | 1,208,666 | 1,267,238 | 10,652,506 | 10,786,389 |
| Industrial: | | | | |
| Colorado | 202,956 | 182,467 | 318,278 | 232,123 |
| Nebraska | 30,816 | 87,531 | 67,010 | 425,171 |
| Iowa | 56,401 | 29,875 | 234,864 | 207,376 |
| Kansas | 2,010,001 | 1,677,072 | 3,518,599 | 2,494,629 |
| Total Industrial | 2,300,174 | 1,976,945 | 4,138,751 | 3,359,299 |
| Transportation: | | | | |
| Colorado | 75,828 | 88,106 | 604,493 | 563,325 |
| Nebraska | 5,910,136 | 5,782,468 | 18,546,617 | 19,331,381 |
| Iowa | 4,068,243 | 3,802,931 | 13,647,342 | 13,059,843 |
| Kansas | 4,331,612 | 3,982,029 | 11,712,421 | 11,284,332 |
| Total Transportation | 14,385,819 | 13,655,534 | 44,510,873 | 44,238,881 |
| Other: | | | | |
| Colorado | — | — | — | — |
| Nebraska | — | 3,315 | — | 4,464 |
| Iowa | — | 7,250 | — | 59,779 |
| Kansas | 4,086 | 2 | 66,152 | 70,855 |
| Total Other | 4,086 | 10,567 | 66,152 | 135,098 |
| Total Volumes Sold | 20,139,794 | 19,162,565 | 84,469,674 | 83,463,057 |

| | Three Months Ended September 30, 2011 | | | Nine Months Ended September 30, 2011 | | |
|--|--|----------------------------|----|---|----------------------------|----|
| | Actual | Variance From Normal | | Actual | Variance From Normal | |
| Heating Degree Days: | | | | | | |
| Colorado | 116 | (38 |)% | 3,717 | (7 |)% |
| Nebraska | 157 | 49 | % | 4,023 | 4 | % |
| Iowa | 235 | 38 | % | 4,780 | 3 | % |
| Kansas* | 54 | 74 | % | 3,085 | 1 | % |
| Combined Gas Utilities Heating Degree Days | 152 | 36 | % | 4,024 | 1 | % |
| | | | | | | |
| | Three Months Ended September 30, 2010 | | | Nine Months Ended September 30, 2010 | | |
| | Actual | Variance From Normal | | Actual | Variance From Normal | |
| Heating Degree Days: | | | | | | |
| Colorado | 29 | (85 |)% | 3,722 | (4 |)% |
| Nebraska | 56 | (38 |)% | 3,923 | 2 | % |
| Iowa | 148 | (6 |)% | 4,229 | (8 |)% |
| Kansas* | 8 | (79 |)% | 3,126 | 3 | % |
| Combined Gas Utilities Heating Degree Days | 58 | (48 |)% | 3,819 | (2 |)% |

* Kansas Gas has a 30-year weather normalization adjustment mechanism in place that neutralizes the impact of weather on revenues at Kansas Gas.

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

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Gas Utilities segment was \$0.6 million for the three months ended September 30, 2011 compared to Net loss of \$0.6 million for the three months ended September 30, 2010 as a result of:

Gross margin increased \$0.7 million primarily due to increased industrial volumes prompted by increased irrigation from dryer weather conditions compared to the same period in the prior year and an increase in margins primarily from the non-regulated business activities.

Operations and maintenance increased \$1.4 million primarily due to an increase in employee compensation and benefit costs .

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

Interest expense, net decreased \$0.7 million primarily due to increased interest income on intercompany lending.

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

Income tax benefit (expense): The effective tax rate for the three months ended September 30, 2011 was favorably impacted by a 2010 tax return true-up adjustment in 2011 primarily related to flow-through treatment of certain property-related temporary differences.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Gas Utilities segment was \$24.3 million for the nine months ended September 30, 2011 compared to Net income of \$18.0 million for the nine months ended September 30, 2010 as a result of:

Gross margin increased \$4.9 million primarily due to rate adjustments and favorable weather than in the same period in the prior year.

Operations and maintenance decreased \$2.3 million primarily due to lower allocation of corporate costs partially offset by higher compensation and benefit costs.

Gain on sale of operating assets represents assets sold in 2010 by Nebraska Gas to the City of Omaha, Nebraska, after a portion of Nebraska Gas' service territory was annexed by the City.

Depreciation and amortization decreased \$1.5 million primarily due to a decrease in depreciation expense resulting from fully depreciated assets and a shift in corporate allocations as a result of higher asset deployment at the Electric Utilities.

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

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

Income tax expense: The effective tax rate for the nine months ended September 30, 2011 was favorably impacted by a 2010 tax return true-up adjustment in 2011 primarily related to flow-through treatment of certain property-related temporary differences.

Regulatory Matters — Utilities Group

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

| | Type of Service | Date Requested | Date Effective | Amount Requested | Amount Approved | Return on Equity | Approved Capital Structure Equity | Debt | | | |
|-----------------------|-----------------|----------------|----------------|------------------|-----------------|-------------------|--------------------------------------|-------------------|--|--|--|
| Nebraska Gas (1) | Gas | 12/2009 | 9/2010 | \$12.1 | \$8.3 | 10.1 % | 52.0 % | 48.0 % | | | |
| Iowa Gas (2) | Gas | 6/2010 | 6/2010 | \$4.7 | \$3.4 | Global Settlement | Global Settlement | Global Settlement | | | |
| Black Hills Power (3) | Electric | 9/2009 | 4/2010 | \$32.0 | \$15.2 | Global Settlement | Global Settlement | Global Settlement | | | |
| Black Hills Power (3) | Electric | 10/2009 | 6/2010 | \$3.8 | \$3.1 | 10.5 % | 52.0 % | 48.0 % | | | |
| Black Hills Power (4) | Electric | 1/2011 | 6/2011 | Not Applicable | \$3.1 | Not Applicable | Not Applicable | Not Applicable | | | |
| Colorado Electric (5) | Electric | 1/2010 | 8/2010 | \$22.9 | \$17.9 | 10.5 % | 52.0 % | 48.0 % | | | |
| Colorado Electric (6) | Electric | 4/2011 | Pending | \$40.2 | Pending | Pending | Pending | Pending | | | |

(1)

In December 2009, Nebraska Gas filed a rate case with the NPSC and interim rates went into effect on March 1, 2010. In August 2010, NPSC issued a decision approving an annual revenue increase of approximately \$8.3 million effective on September 1, 2010. A refund to customers for the difference between interim rates and approved rates was completed in the first quarter of 2011. The Nebraska Public Advocate filed an initial appeal which was denied. The Public Advocate subsequently filed a notice of appeal with the Court of Appeals.

(2) In June 2010, Iowa Gas filed a request with the IUB for a \$4.7 million, or 2.9%, revenue increase to recover the cost of capital investments made in our gas distribution system and other expense increases incurred since December 2008. Interim rates, subject to refund, equal to a \$2.6 million increase, or 1.6%, in revenues went into effect on June 18, 2010. In August 2010, we reached a settlement with the OCA for a revenue increase of \$3.4 million and hearings on the settlement were held in October 2010. Approval from the IUB of a modified settlement for a revenue increase of \$3.4 million was received in February 2011.

(3) This rate case was previously described in our 2010 Annual Report on Form 10-K.

(4) In May 2011, the SDPUC approved an Environmental Improvement Cost Recovery Adjustment tariff for Black Hills Power. This tariff, which was implemented to recover Black Hills Power's investment of \$25 million for pollution control equipment at the PacifiCorp operated Wyodak plant, went into effect June 1, 2011 with an annual revenue increase of \$3.1 million.

(5) On January 5, 2010, Colorado Electric filed a rate case with CPUC requesting an electric revenue increase primarily related to the recovery of rising costs from electricity supply contracts, as well as recovery for investment in equipment and electricity distribution facilities necessary to maintain and strengthen the reliability of the electric delivery system. Colorado Electric requested a \$22.9 million, or approximately 12.8%, increase in annual revenue. In August 2010, the CPUC approved a settlement agreement for \$17.9 million in annual revenue with a return on equity of 10.5% and a capital structure of 52% equity and 48% debt. New rates were effective August 6, 2010.

Included in the rate case order was a provision that off-system sales margins be shared with customers commencing August 6, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC has therefore required that the off-system operating income earned beginning August 6, 2010 be deferred on the balance sheet until settlement of the sharing mechanism. Since August 2010, \$1.3 million in off-system operating income has been deferred. The determination for a sharing mechanism is now being considered as part of the rate case filed with the CPUC by Colorado Electric discussed below.

(6) On April 28, 2011, Colorado Electric filed a request with the CPUC for an annual revenue increase of \$40.2 million, or 18.8%, to recover costs and a return on capital associated with the 180 MW generating facilities currently under construction, associated infrastructure assets and other utility expenses, including the PPA with Colorado IPP. The facilities are expected to be in operation by the end of 2011. This rate request was amended by Colorado Electric's Rebuttal Testimony filed on October 14, 2011. A hearing on the rate case with the CPUC began November 1, 2011.

Non-regulated Energy Group

We report four segments within our Non-regulated Energy Group: Oil and Gas, Coal Mining, Energy Marketing and Power Generation. An analysis of results from our Non-regulated Energy Group's operating segments follows:

Oil and Gas

| | Three Months Ended | | Nine Months Ended | |
|--|-----------------------|----------|-----------------------|----------|
| | September 30, 2011 | 2010 | September 30, 2011 | 2010 |
| | (in thousands) | | | |
| Revenue | \$19,163 | \$19,354 | \$55,907 | \$57,755 |
| Operations and maintenance | 9,573 | 9,731 | 30,327 | 29,964 |
| Depreciation, depletion and amortization | 7,714 | 7,326 | 22,637 | 20,279 |
| Total operating expenses | 17,287 | 17,057 | 52,964 | 50,243 |
| Operating income (loss) | 1,876 | 2,297 | 2,943 | 7,512 |
| Interest expense | (1,460 |) (1,565 |) (4,232 |) (3,738 |
| Other income (expense), net | 54 | 129 | (43 |) 671 |

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| | | | | | |
|------------------------------|-------|-------|--------|-----------|---|
| Income tax (expense) benefit | (229 |) (25 |) 779 | (1,040 |) |
| Net income (loss) | \$241 | \$836 | \$(553 |) \$3,405 | |

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|-------------------------------------|-----------|------------------------------------|-----------|
| | 2011 | 2010 | 2011 | 2010 |
| Production: | | | | |
| Bbls of oil sold | 98,950 | 99,950 | 303,401 | 268,768 |
| Mcf of natural gas sold | 2,289,137 | 2,285,016 | 6,671,176 | 6,793,866 |
| Mcf equivalent sales | 2,882,837 | 2,884,716 | 8,491,582 | 8,406,474 |
| | | | | |
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Average price received: ^(a) | | | | |
| Gas/Mcf ^(b) | \$4.24 | \$4.64 | \$4.39 | \$5.12 |
| Oil/Bbl | \$82.76 | \$80.87 | \$76.25 | \$81.70 |
| | | | | |
| Depletion expense/Mcfe | \$2.38 | \$2.18 | \$2.38 | \$2.11 |

(a) Net of hedge settlement gains and losses

(b) Exclusive of natural gas liquids

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

| | Three Months Ended September 30, 2011 | | | | Three Months Ended September 30, 2010 | | | |
|------------------------|---------------------------------------|--|---------------------|--------|---------------------------------------|--|---------------------|--------|
| | LOE | Gathering, Compression and Processing | Production Taxes | Total | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | \$1.06 | \$0.25 | \$0.52 | \$1.83 | \$1.21 | \$0.30 | \$0.48 | \$1.99 |
| Piceance | 0.80 | 0.63 | 0.28 | 1.71 | 1.06 | 0.53 | 0.23 | 1.82 |
| Powder River | 1.20 | — | 1.26 | 2.46 | 1.14 | — | 0.92 | 2.06 |
| Williston | 1.01 | — | 1.74 | 2.75 | 1.19 | — | 1.16 | 2.35 |
| All other properties | 0.62 | — | 0.38 | 1.00 | 0.94 | — | 0.44 | 1.38 |
| Total weighted average | \$0.99 | \$0.18 | \$0.72 | \$1.89 | \$1.13 | \$0.19 | \$0.59 | \$1.91 |
| | | | | | | | | |
| | Nine Months Ended September 30, 2011 | | | | Nine Months Ended September 30, 2010 | | | |
| | LOE | Gathering, Compression and Processing | Production Taxes | Total | LOE | Gathering, Compression and Processing | Production Taxes | Total |
| San Juan | \$1.17 | \$0.35 | \$0.54 | \$2.06 | \$1.31 | \$0.32 | \$0.58 | \$2.21 |
| Piceance | 0.77 | 0.73 | 0.06 | 1.56 | 0.66 | 0.65 | 0.29 | 1.60 |
| Powder River | 1.31 | — | 1.31 | 2.62 | 1.16 | — | 1.02 | 2.18 |
| Williston | 0.59 | — | 1.58 | 2.17 | 1.33 | — | 1.21 | 2.54 |
| All other properties | 1.17 | — | 0.26 | 1.43 | 1.03 | — | 0.30 | 1.33 |
| Total weighted average | \$1.11 | \$0.23 | \$0.70 | \$2.04 | \$1.16 | \$0.21 | \$0.62 | \$1.99 |

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Oil and Gas segment was \$0.2 million for the three months ended September 30, 2011 compared to Net income of \$0.8 million for the same period in 2010 as a result of:

Revenue was comparable to the same period in the prior year with offsetting changes of a 2% higher average hedged oil price received and 1% higher natural gas volumes, exclusive of gas liquids, partially offset by a 1% decrease in oil volumes and a 9% decrease in average hedged price received for natural gas. Oil volumes declined primarily due to natural production declines from producing properties partially offset by production gains in our ongoing Bakken drilling program.

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

Depreciation, depletion and amortization increased \$0.4 million primarily due to a higher depletion rate, resulting primarily from higher finding and development costs for our Bakken oil drilling program.

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

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

Income tax (expense) benefit: The effective tax rate in 2011 was negatively impacted primarily by the true-up of percentage depletion related to the filing of the 2010 tax return while 2010 was positively impacted by a \$0.4 million re-measurement of a previously recorded uncertain tax position due to a settlement agreement with the IRS.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net loss for the Oil and Gas segment was \$0.6 million for the nine months ended September 30, 2011 compared to Net income of \$3.4 million for the same period in 2010 as a result of:

Revenue decreased \$1.8 million due to a 14% decrease in the average hedged price received for natural gas and a 7% decrease in the average hedged price received for oil, as well as a 2% decline in gas volumes, exclusive of gas liquids, partially offset by a 13% increase in crude oil volumes. The average crude oil price received was influenced by fixed price swaps previously entered into at prices significantly below current market prices. The increase in oil volumes was favorably impacted by volumes at new wells in our ongoing Bakken drilling program in North Dakota.

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

Depreciation, depletion and amortization increased \$2.4 million primarily due to a higher depletion rate, resulting primarily from higher finding and development costs on a per Mcfe basis for our Bakken oil drilling program.

Interest expense increased \$0.5 million primarily due to inter-company interest allocations on inter-company borrowings.

Other income (expense), net decreased \$0.7 million due to lower earnings from equity investments.

Income tax (expense) benefit: The effective tax rate in 2011 was positively impacted primarily by the tax benefit generated by percentage depletion while the effective tax rate for 2010 was positively impacted by a \$0.4 million re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS.

Coal Mining

| | Three Months Ended | | Nine Months Ended | | |
|--|--------------------|-----------|-------------------|------------|---|
| | September 30, | | September 30, | | |
| | 2011 | 2010 | 2011 | 2010 | |
| | (in thousands) | | | | |
| Revenue | \$ 17,835 | \$ 14,277 | \$ 48,870 | \$ 43,306 | |
| Operations and maintenance | 14,171 | 10,750 | 41,754 | 30,041 | |
| Depreciation, depletion and amortization | 5,151 | 3,342 | 14,364 | 9,553 | |
| Total operating expenses | 19,322 | 14,092 | 56,118 | 39,594 | |
| Operating income (loss) | (1,487 |) 185 | (7,248 |) 3,712 | |
| Interest income, net | 972 | 1,086 | 2,868 | 2,191 | |
| Other income | 532 | 510 | 1,650 | 1,593 | |
| Income tax benefit (expense) | 538 | (108 |) 1,606 | (1,403 |) |
| Net income (loss) | \$ 555 | \$ 1,673 | \$ (1,124 |) \$ 6,093 | |

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

| | Three Months Ended | | Nine Months Ended | |
|---------------------------------|--------------------|-------|-------------------|--------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Tons of coal sold | 1,550 | 1,489 | 4,155 | 4,340 |
| Cubic yards of overburden moved | 3,873 | 4,482 | 10,261 | 11,805 |

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Coal Mining segment was \$0.6 million for the three months ended September 30, 2011 compared to Net income of \$1.7 million for the same period in 2010, as a result of:

Revenue increased \$3.6 million primarily due to a 20% increase in average sales price per ton and a 4% increase in coal volumes sold. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts. Approximately 40% of our coal production is sold under sales contracts that include adjustments to the sales price based on actual mining cost increases. Most of our remaining production is sold under contracts where the sales price may escalate based on published indices, which may not necessarily represent changes in actual mining costs.

Operations and maintenance increased \$3.4 million which is reflective of longer haul distances and higher overburden stripping costs in the current phase of our mining. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, clay parting removal, fuel, staffing levels for our train load-out facility and weather conditions. As noted above, a portion of our production is sold under contracts that have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income, and are expected to continue to negatively impact 2011 results. Previous periods also include the capitalization of certain costs associated with mine infrastructure, including our in-pit conveyor system that is used to transport coal to mine-mouth generation facilities.

Depreciation, depletion and amortization increased \$1.8 million primarily due to higher depreciation on reclamation related costs and mining equipment.

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

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

Income tax benefit (expense): The effective tax rate for the three months ended September 30, 2011 was favorably impacted by a true-up of percentage depletion related to the filing of the 2010 tax return.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net loss for the Coal Mining segment was \$1.1 million for the nine months ended September 30, 2011 compared to Net income of \$6.1 million for the same period in 2010 as a result of:

Revenue increased \$5.6 million primarily due to an 18% increase in average sales price received per ton, partially offset by 4% lower coal volumes sold. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts. Approximately 40% of our coal production is sold under sales contracts that include adjustments to the sales price based on actual mining cost increases. Most of our remaining production is sold under contracts where the sales price may escalate based on published indices, which may not necessarily represent changes in actual mining costs.

Operations and maintenance increased \$11.7 million which is reflective of longer haul distances and higher overburden stripping costs in the current phase of our mining. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, clay parting removal, fuel, and staffing levels for our train load-out facility. As noted above, over half of our production is sold under contracts that have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income, and are expected to continue to negatively impact 2011 results. Previous periods also include the capitalization of certain costs associated with mine infrastructure, including our in-pit conveyor system that is used to transport coal to mine-mouth generation facilities.

Depreciation, depletion and amortization increased \$4.8 million primarily related to higher depreciation on reclamation related costs and mining equipment.

Interest income, net increased \$0.7 million primarily due to increased inter-company debt balances.

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

Income tax benefit (expense): The effective income tax rate for 2011 was favorably impacted by a true-up of percentage depletion related to the filing of the 2010 tax return.

Energy Marketing

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|-------------------------------|-------------------------------------|---------|------------------------------------|----------|
| | 2011 | 2010 | 2011 | 2010 |
| | (in thousands) | | | |
| Gross margin — | | | | |
| Realized gross margin | \$25,481 | \$(704) |) \$31,931 | \$13,994 |
| Unrealized gross margin | (18,543 |) 9,677 | (10,052 |) 13,646 |
| Total gross margin | 6,938 | 8,973 | 21,879 | 27,640 |
| Operating expenses | 5,702 | 6,349 | 18,033 | 17,807 |
| Depreciation and amortization | 159 | 128 | 442 | 387 |
| Total operating expenses | 5,861 | 6,477 | 18,475 | 18,194 |
| Operating income | 1,077 | 2,496 | 3,404 | 9,446 |
| Interest expense, net | (430 |) (380 |) (1,087 |) (1,942 |

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| | | | | |
|------------------------------|-------|---------|---------|----------|
| Other income (expense), net | (6 |) (1 |) (4 |) 152 |
| Income tax (expense) benefit | (368 |) (745 |) (986 |) (2,766 |
| Net income (loss) | \$273 | \$1,370 | \$1,327 | \$4,890 |

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Gross margin by commodity (in thousands):

| | Three Months Ended | | | | | Total |
|--------------------|--------------------|-----------|---------------------|----------------------|------------------------------|----------|
| | Natural Gas | Crude Oil | Coal ^(a) | Power ^(a) | Environmental ^(a) | |
| September 30, 2011 | | | | | | |
| Realized | \$16,752 | \$11,225 | \$(1,200) | \$(1,292) | \$(4) | \$25,481 |
| Unrealized | (12,138) | (2,083) | (2,005) | (2,174) | (143) | (18,543) |
| Total | \$4,614 | \$9,142 | \$(3,205) | \$(3,466) | \$(147) | \$6,938 |
| September 30, 2010 | | | | | | |
| Realized | \$(3,897) | \$2,952 | \$241 | \$— | \$— | \$(704) |
| Unrealized | 6,016 | (1,268) | 4,929 | — | — | 9,677 |
| Total | \$2,119 | \$1,684 | \$5,170 | \$— | \$— | \$8,973 |
| | Nine Months Ended | | | | | Total |
| | Natural Gas | Crude Oil | Coal ^(a) | Power ^(a) | Environmental ^(a) | |
| September 30, 2011 | | | | | | |
| Realized | \$20,662 | \$13,760 | \$406 | \$(2,893) | \$(4) | \$31,931 |
| Unrealized | (10,876) | (2,207) | 1,358 | 1,697 | (24) | (10,052) |
| Total | \$9,786 | \$11,553 | \$1,764 | \$(1,196) | \$(28) | \$21,879 |
| September 30, 2010 | | | | | | |
| Realized | \$8,670 | \$5,526 | \$(202) | \$— | \$— | \$13,994 |
| Unrealized | 5,056 | (504) | 9,094 | — | — | 13,646 |
| Total | \$13,726 | \$5,022 | \$8,892 | \$— | \$— | \$27,640 |

(a) Coal marketing activity began June 1, 2010, Power marketing began late in the third quarter of 2010, and Environmental marketing began late in the third quarter of 2010 with no activity until second quarter of 2011.

Following is a summary of average daily quantities marketed:

| | Three Months Ended | | Nine Months Ended | |
|-------------------------------------|--------------------|-----------|-------------------|-----------|
| | September 30, | | September 30, | |
| | 2011 | 2010 | 2011 | 2010 |
| Natural gas physical sales — MMBtus | 1,493,357 | 1,666,674 | 1,581,945 | 1,589,261 |
| Crude oil physical sales — Bbls | 26,628 | 19,410 | 23,729 | 17,947 |
| Coal physical sales — Tons | 34,352 | 28,549 | 34,851 | 28,407 |
| Power - MWh ^(a) | 593 | — | 262 | — |

(a) Coal marketing activity began June 1, 2010 and Power marketing began late in the third quarter of 2010.

Natural gas, crude oil and coal inventory held by Energy Marketing primarily consists of gas held in storage and crude oil inventory held to meet pipeline line pack requirements. Natural gas storage is held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date. Crude oil line pack is held to satisfy requirements by pipelines on which the company transports crude oil. Quantities held were as follows:

| | As of September 30, 2011 | As of December 31, 2010 | As of September 30, 2010 |
|--------------------------------|-----------------------------|----------------------------|-----------------------------|
| Natural gas (MMBtu) | 7,930,831 | 14,922,353 | 16,262,328 |
| Crude oil (Bbl) | 194,141 | 198,052 | 156,000 |
| Coal (Ton) | 59,859 | 1,529 | — |
| Renewable Energy Credits (MWh) | 31,280 | — | — |

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Energy Marketing segment was \$0.3 million for the three months ended September 30, 2011 compared to Net income of \$1.4 million for the same period in 2010 as a result of:

Gross margin decreased \$2.0 million primarily due to lower unrealized marketing margins of \$28.2 million partially offset by increased realized margins of \$26.2 million. The decrease in unrealized margins primarily reflects lower natural gas margins, lower margins from the coal portfolio and losses from the power marketing portfolio. These decreases in unrealized marketing margins were partially offset by higher realized natural gas and crude oil marketing margins.

Operating expenses decreased \$0.6 million primarily due to a lower provision for compensation related to decreased margins, partially offset by higher compensation and benefit expenses relating to additional staff marketing new commodities and new geographic regions.

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

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

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

Income tax (expense) benefit: The effective income tax rate for the three months ended September 30, 2011 increased primarily due to permanent differences related to the filing of the 2010 tax return.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Energy Marketing segment was \$1.3 million for the nine months ended September 30, 2011 compared to a Net income of \$4.9 million for the same period in 2010 as a result of:

Gross margin decreased \$5.8 million primarily driven by lower unrealized marketing margins of \$23.7 million partially offset by an increase of \$17.9 million in realized marketing margins. The decrease in unrealized margins primarily reflects lower natural gas and coal margins. Realized marketing margins include realized gains from natural gas and crude oil, partially offset by losses from power marketing.

Operating expenses were comparable to the same period in the prior year.

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

Interest expense, net decreased \$0.9 million primarily due to lower inter-company borrowings.

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

Income tax (expense) benefit: The effective income tax rate for the nine months ended September 30, 2011 was comparable to the same period in the prior year.

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Power Generation

| | Three Months Ended | | Nine Months Ended | |
|---|-----------------------|---------|-----------------------|----------|
| | September 30, 2011 | 2010 | September 30, 2011 | 2010 |
| | (in thousands) | | | |
| Revenue | \$8,100 | \$7,855 | \$23,500 | \$22,602 |
| Operating, general and administrative costs | 4,602 | 3,724 | 12,881 | 12,289 |
| Depreciation and amortization | 1,064 | 1,048 | 3,168 | 3,374 |
| Gain on sale of operating asset | — | — | — | — |
| Total operating expense (income) | 5,666 | 4,772 | 16,049 | 15,663 |
| Operating income | 2,434 | 3,083 | 7,451 | 6,939 |
| Interest expense, net | (1,835) | (2,194) | (5,461) | (6,177) |
| Other (expense) income | (5) | (266) | 1,220 | 894 |
| Income tax (expense) benefit | (257) | (48) | (1,139) | (417) |
| Net income (loss) | \$337 | \$575 | \$2,071 | \$1,239 |

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

| | Three Months Ended | | Nine Months Ended | |
|--|-----------------------|--------|-----------------------|--------|
| | September 30, 2011 | 2010 | September 30, 2011 | 2010 |
| Contracted power plant fleet availability: | | | | |
| Coal-fired plant | 97.1 | %96.9 | % 98.9 | %98.6 |
| Natural gas-fired plants | 100.0 | %100.0 | % 100.0 | %100.0 |
| Total availability | 98.1 | %98.2 | % 99.3 | %99.2 |

In January 2011, we sold our ownership interests in the partnerships which own the Idaho facilities.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net income for the Power Generation segment was \$0.3 million for the three months ended September 30, 2011 compared to Net income of \$0.6 million for the same period in 2010 as a result of:

Revenue was comparable to the same period in the prior year.

Operations and maintenance increased \$0.9 million primarily due to higher maintenance costs at Black Hills Wyoming, higher transmission costs and additional costs incurred at Colorado IPP as construction progresses and employees prepare for operations of the facilities.

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 (expense) income decreased \$0.3 million due to lower earnings from our partnership investments than in 2010.

Income tax (expense) benefit: The effective tax rate for the three months ended September 30, 2011 increased over the prior period due to unfavorable adjustments related to true-up of research and development credits.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net income for the Power Generation segment was \$2.1 million for the nine months ended September 30, 2011 compared to Net income of \$1.2 million for the same period in 2010 as a result of:

Revenue increased \$0.9 million primarily due to increased sales from Wygen I, which incurred a forced outage and a major overhaul in the same period in the prior year.

Operations and maintenance increased \$0.6 million primarily due to higher coal costs and higher costs associated with Colorado IPP as construction progresses and employees prepare for operations of the facilities.

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

Interest expense, net decreased \$0.7 million due to the ability to capitalize additional interest at Colorado IPP and increased inter-company interest income at Black Hills Wyoming.

Other (expense) income increased due to the gain on sale of our ownership interest in the partnership that owned the Idaho generation facilities.

Income tax expense: The effective tax rate for the nine months ended September 30, 2011 increased over the prior period due to an unfavorable adjustment related to true-up of research and development credits.

Corporate

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Net loss for Corporate was \$27.9 million for the three months ended September 30, 2011 compared to Net loss of \$10.1 million for the three months ended September 30, 2010 as a result of an unrealized before tax, non-cash mark-to-market loss on certain interest rate swaps for the quarter ended September 30, 2011 of approximately \$38.2 million compared to a \$13.7 million unrealized before tax, mark-to-market non-cash loss on these interest rate swaps in the prior year. Additionally, our income tax expense for the three months ended September 30, 2010 decreased \$2.0 million due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS relating primarily to depreciation method changes.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Net loss for Corporate was \$36.1 million compared to Net loss of \$34.2 million as a result of an unrealized net before tax, mark-to-market loss on certain interest rate swaps for the nine months ended September 30, 2011 of approximately \$40.6 million compared to a \$41.7 million unrealized net before tax, mark-to-market non-cash loss on these interest rate swaps in the prior year. Additionally, our income tax expense in 2010 decreased \$2.0 million due to a re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS relating primarily to depreciation method changes.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2010 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 2010 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

The following table summarizes our cash flows for the nine months ended September 30, 2011 and 2010 (in thousands):

| Cash provided by (used in): | 2011 | 2010 | Increase (Decrease) |
|-----------------------------|-------------|-------------|---------------------|
| Operating activities | \$206,527 | \$125,761 | \$80,766 |
| Investing activities | \$(326,862) | \$(253,755) | \$(73,107) |
| Financing activities | \$162,676 | \$74,068 | \$88,608 |

Year-to-Date 2011 Compared to Year-to-Date 2010

Operating Activities

Net cash provided by operating activities was \$80.8 million higher for the nine months ended September 30, 2011 than the same period in 2010 primarily attributable to:

Cash earnings (net income plus non-cash adjustments) were \$26.2 million higher for the nine months ended September 30, 2011 than for the same period the prior year.

Net outflows from operating assets and liabilities were \$3.9 million for the nine months ended September 30, 2011, a decrease of \$44.0 million from the same period in the prior year as a result of:

Net outflows from working capital accounts were \$31.3 million for the nine months ended September 30, 2011, compared to outflows of \$52.9 million from the prior year. The change in net outflows relate to normal working capital changes including the effect of the seasonality of our gas utility operations as well as the following: increased 2011 inflows of \$53 million from changes in Materials, supplies and fuel primarily comprised of higher withdrawals of gas storage inventories by Energy Marketing of \$45 million, 2011 inflow of \$16 million as a result of a settlement reached with the IRS, and Energy Marketing experienced higher outflows in the current period related to higher margin posted on marketing transactions of \$41 million offset by a refund of cash collateral of \$25 million posted by the Corporate segment for the de-designated hedges.

Inflows from changes in regulatory assets and regulatory liabilities, primarily related to collection of gas costs by our Gas Utilities.

Cash contributions to the defined benefit pension plan were \$11.0 million in 2011 compared to \$30.0 million in 2010.

Investing Activities

Net cash used in investing activities was \$73.1 million higher for the nine months ended September 30, 2011 than in the same period in 2010 reflecting higher capital additions. During 2011, cash outflows for property, plant and equipment additions totaled \$328.5 million, including the on-going completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and 200 MW of natural gas-fired electric generation at Black Hills Colorado IPP, and property maintenance capital and development drilling at the Oil and Gas segment.

Financing Activities

Net cash provided by financing activities was \$88.6 million higher for the nine months ended September 30, 2011 than in the same period in 2010 primarily due to increased borrowings to finance our construction activities. During the nine months ended September 30, 2011, we refinanced a portion of the borrowings on our Revolving Credit Facility with a new \$150 million corporate term loan which was used to pay down a portion of our Revolving Credit Facility, paid \$6.2 million of long-term debt primarily related to required payments on the Black Hills Wyoming Project Financing, and paid \$43.2 million of cash dividends on common stock.

Dividends

Dividends paid on our common stock totaled \$43.2 million for the nine months ended September 30, 2011, or \$1.095 per share. On October 27, 2011, our Board of Directors declared an additional quarterly dividend of \$0.365 per share

payable December 1, 2011, which is equivalent to an annual dividend rate of \$1.46 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Financing Transactions and Short-Term Liquidity

Our principal sources of short-term liquidity are our Revolving Credit Facility and cash provided by operations. In addition to availability under our Revolving Credit Facility described below, as of September 30, 2011, we had approximately \$75 million of cash unrestricted for operations.

Revolving Credit Facility

Our \$500 million Revolving Credit Facility expiring April 14, 2013 can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 1.75%, 2.75% and 2.75%, respectively. The facility contains a commitment fee to be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.5%. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to \$600 million.

At September 30, 2011, we had borrowings of \$209 million and letters of credit outstanding of \$42 million on our Revolving Credit Facility. Available capacity remaining on our Revolving Credit Facility was approximately \$249 million at September 30, 2011.

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 maintenance of certain financial covenants including a minimum consolidated net worth and a recourse leverage ratio not to exceed 0.65 to 1.00.

Our consolidated net worth was \$1.1 billion at September 30, 2011, which was approximately \$216.7 million in excess of the net worth we were required to maintain under the Revolving Credit Facility. At September 30, 2011, our long-term debt ratio was 54.1%, our total debt leverage ratio (long-term debt and short-term debt) was 60.2%, and our recourse leverage ratio was approximately 61.3%. We were in compliance with these covenants as of September 30, 2011.

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

Enserco Credit Facility

Enserco utilizes a two-year, \$250 million committed credit facility expiring in May 2012 which includes an accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility to \$350 million. Maximum borrowings under the facility are subject to a sublimit of \$50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%. Enserco was in compliance with its debt covenants as of September 30, 2011.

At September 30, 2011, \$132.6 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

Corporate Term Loans

In June 2011, we entered into a one-year \$150 million unsecured, single draw, term loan with CoBank, the Bank of Nova Scotia and U.S. Bank due on June 24, 2012. The cost of borrowing under the loan is based on a spread of 125 basis points over LIBOR (1.63% at September 30, 2011). The covenants are substantially the same as those included

in the Revolving Credit Facility. We were in compliance with these covenants as of September 30, 2011.

In December 2010, we entered into a one-year \$100.0 million term loan with J.P. Morgan and Union Bank due in December 2011. On September 30, 2011, we extended that term loan for two-years under the existing terms to September 13, 2013. The cost of borrowing under this Term Loan was based on a spread of 137.5 basis points over LIBOR (1.625% at September 30, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility. We were in compliance with these covenants as of September 30, 2011.

Dividend Restrictions

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of September 30, 2011, the restricted net assets at our Electric and Gas Utilities were approximately \$164.3 million.

Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, Enserco may be restricted from making dividend payments to the parent company. Enserco's restricted net assets at September 30, 2011 were \$163.8 million compared to \$93.0 million at December 31, 2010.

As a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of \$100 million. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation, which is the parent of Black Hills Wyoming.

Future Financing Plans

We have substantial capital expenditures in 2011, which are primarily due to the construction of additional utility and IPP generation to serve Colorado Electric. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility, term loans and long-term financings. We settled the equity forward instrument executed in November 2010 on November 1, 2011. We may complete an additional long-term senior unsecured debt financing at the holding company level in 2012 and we are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and equity issuance. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, due to significant ongoing capital projects, we may exceed this level on a temporary basis. We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements.

Equity Forward

In November 2010, we entered into a Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Under the Forward Agreement on November 10, 2010, we agreed to issue to J.P. Morgan 4,000,000 shares of our common stock at an initial forward price of \$28.70875 per share. On December 7, 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares under the same terms as the original Forward Agreement (together with the Forward Agreement, the "Forward Agreements").

On November 1, 2011, the Equity Forward Agreements with J. P. Morgan were settled by issuing 4,413,519 shares of Black Hills Corporation common stock in return for approximately \$120 million in net cash proceeds. The proceeds were used to pay down a portion of the Revolving Credit Facility.

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 income statement. For the three and nine months ended September 30, 2011, respectively, we recorded \$38.2 million and \$40.6 million pre-tax unrealized mark-to-market non-cash losses on the swaps. The mark-to-market value on these swaps was a liability of \$94.6 million at September 30, 2011. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately \$0.4 million. These swaps hedge interest rate exposure for periods to 2018 and 2028 and have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011. We anticipate extending these agreements upon the mandatory early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Colorado Electric, Black Hills Power and Cheyenne Light customers, and because of our upcoming holding company debt maturities, which are \$225 million and \$250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the termination dates.

In addition, we have \$150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 5.25 years. These swaps have been designated as cash flow hedges, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of \$27.8 million at September 30, 2011.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2010 Annual Report on Form 10-K filed with the SEC.

Energy Marketing Commodities

Our Energy Marketing segment uses derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. These activities can have liquidity impacts which the Company monitors and manages in accordance with its Risk Management Policies and Procedures. The primary sources of liquidity for our Energy Marketing segment are: cash from operations, the Enserco Credit Facility and advances of cash from the parent company.

In our Energy Marketing segment, our largest counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize credit risk through an evaluation of the counterparties' financial condition and credit ratings and collateral requirements under certain circumstances, including the use of master netting agreements. We continuously monitor collections and payments from our counterparties.

The addition of the coal, environmental, and power marketing businesses has not and is not expected to result in a significant increase to the liquidity requirement of the Energy Marketing segment in the near term.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms, including collateral requirements. As of September 30, 2011, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

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

In addition, as of September 30, 2011, Black Hills Power's first mortgage bonds were rated as follows:

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

Capital Requirements

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

| | Expenditures for the Nine Months Ended September 30, 2011 | Total 2011 Planned Expenditures | Total 2012 Planned Expenditures | Total 2013 Planned Expenditures |
|---|--|---------------------------------------|---------------------------------------|---------------------------------------|
| Utilities: | | | | |
| Electric Utilities ^{(1) (2) (3)} | \$ 131,824 | \$ 185,200 | \$ 231,500 | \$ 309,800 |
| Gas Utilities | 29,525 | 48,200 | 46,000 | 54,700 |
| Non-regulated Energy: | | | | |
| Oil and Gas ⁽⁴⁾ | 59,294 | 79,100 | 97,200 | 123,500 |
| Power Generation ⁽⁵⁾ | 87,760 | 95,700 | 2,900 | 4,900 |
| Coal Mining | 7,856 | 12,800 | 18,800 | 7,200 |
| Energy Marketing | 2,075 | 4,200 | 5,400 | 5,700 |
| Corporate | 10,849 | 16,000 | 25,800 | 18,700 |
| | \$ 329,183 | \$ 441,200 | \$ 427,600 | \$ 524,500 |

(1) The 2011 total planned expenditures include capital requirements associated with the on-going construction of the 180 MW gas-fired power generation facility to serve our Colorado Electric customers. We spent \$57.6 million during the first nine months of 2011. The total construction cost of the facility is expected to be approximately \$227 million, excluding transmission, and construction is expected to be completed by the end of 2011.

(2) Planned 2011 expenditures include expected spending of \$9.6 million for a planned wind project for Colorado Electric.

(3) Planned generation expenditures for 2012 and 2013 include (a) \$34.7 million for 2012 and \$149.4 million for 2013 for 132 MW of new generation and related electric and gas transmission at Cheyenne Light and Black Hills Power for which the CPCN was filed on November 1, 2011 subject to acceptance of the CPCN and receipt of air permits, (b) approximately \$16.9 million for 2012 for our 50% share of the Colorado Electric wind project, subject to CPUC approval, (c) \$43.5 million and \$7.8 million, respectively, for 2012 and 2013 for the 88 MW of which 42 MW will be utility owned gas-fired generation at Colorado Electric, also subject to CPUC approval, and (d) \$14.6 million for the Southern Connector Transmission Project at Colorado Electric in 2012.

(4) Our Oil and Gas segment planned expenditures in 2011 have increased \$30.2 million from our planned expenditures disclosed in our 2010 Annual Report on Form 10-K, primarily due to development in the Bakken formation and our Mancos test program.

(5)

Our Power Generation segment was awarded the bid to provide 200 MW of generation capacity for a 20-year period to Colorado Electric. We spent \$87.1 million during the first nine months of 2011. The total construction cost of the new facility is expected to be approximately \$260 million, and construction is expected to be completed by the end of 2011.

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

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment decreased \$13.3 million from \$83.5 million at December 31, 2010 to \$70.2 million at September 30, 2011. Approximately \$36.9 million of the firm transportation and storage fee obligations relate to the 2011-2013 period with the remainder occurring thereafter.

Construction of a 180 MW power generation facility by our Colorado Electric utility and 200 MW power generation facility by our Power Generation segment is progressing. Cost of construction is expected to be approximately \$227 million for Colorado Electric and \$260 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. As of September 30, 2011, we have committed contracts of 100% for the construction and construction was 99% complete for the Colorado Electric utility, and we have committed contracts of 100% and construction was 97% complete, for the Power Generation segment.

Colorado Electric filed a proposal with the CPUC to rate base 50% ownership in a 29 MW wind turbine project. As part of this project, on July 15, 2011, Colorado Electric signed a wind turbine supply agreement with Vestas-American Wind Technologies, Inc. for \$33.3 million.

Guarantees

Except as noted below, there have been no changes to guarantees provided from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2010 Annual Report on Form 10-K.

The guarantee for up to \$7.0 million of the obligations of Enserco under an agency agreement expired in the first quarter of 2011.

The construction of the office building in Papillion, Nebraska was completed and the guarantee for \$6.0 million was terminated upon purchase of the building in April 2011.

In June 2011, a guarantee to Colorado Interstate Gas was amended from \$9.3 million to \$10.0 million and the expiration date was extended to July 31, 2012. All other terms remained the same.

In June 2011, we issued a guarantee to Cross Timbers Energy Services for the performance and payment obligations of BHUH for natural gas supply purchases up to \$7.5 million. The guarantee expires on June 30, 2012 or upon 30 days written notice to the counterparty.

In July 2011, we issued a guarantee to Vestas-American Wind Technology, Inc. for the performance and payment obligations of Colorado Electric for \$33.3 million relating to the purchase of wind turbines for a Colorado Electric wind power generation project. This guarantee will remain in effect until satisfaction of Colorado Electric's contractual obligation. We expect the guarantee to expire on or about January 15, 2013.

New Accounting Pronouncements

Other than the pronouncements reported in our 2010 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

FORWARD-LOOKING INFORMATION

This report contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A of our 2010 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q, and other reports that we file with the SEC from time to time, and the following:

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

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

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

We expect to fund a portion of our capital requirements for the planned regulated and non-regulated generation additions through a combination of long-term debt and issuance of equity.

We expect to make approximately \$441.2 million, \$427.6 million and \$525 million of capital expenditures in 2011, 2012 and 2013, respectively. Some important factors that could cause actual expenditures to differ materially from those anticipated include:

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

Forecasted capital expenditures associated with our Oil and Gas segment are driven, in part, by current market prices. Changes in crude oil and natural gas prices may cause us to change our planned capital expenditures related to our oil and gas operations.

Our ability to complete our planned capital expenditures associated with our Oil and Gas segment may be impacted by proposed government regulations and regulatory requirements, including those related to hydraulic fracturing services, availability of drilling rigs and other support services, and weather conditions.

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

We expect contributions to our defined benefit pension plans to be approximately \$0.0 million and \$7.9 million for the remainder of 2011 and for 2012, respectively. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

- The actual value of the plans' invested assets.
- The discount rate used in determining the funding requirement.
- The outcome of pending labor negotiations relating to benefit participation of our collective bargaining agreements.

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

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

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

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

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

We are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and equity issuance. Some important factors that could cause actual results to differ materially from those anticipated include:

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

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

The effect of Dodd-Frank and the regulations to be adopted thereunder on our use of derivative instruments in connection with our Energy Marketing segment activities, and to hedge our expected production of oil and natural gas and on our use of interest rate derivative instruments.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

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

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

| | September 30, 2011 | December 31, 2010 | September 30, 2010 |
|-------------------------------------|-----------------------|----------------------|-----------------------|
| Net derivative (liabilities) assets | \$(10,064 |) \$(7,188 |) \$(16,078 |
| Cash collateral | 12,058 | 10,355 | 20,519 |
| | \$1,994 | \$3,167 | \$4,441 |

Non-Regulated Trading Activities

The following table provides a reconciliation of Energy Marketing segment activity in our marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the nine months ended September 30, 2011 (in thousands):

| | | |
|---|----------|-----|
| Total fair value of energy marketing positions marked-to-market at December 31, 2010 | \$23,418 | (a) |
| Net cash settled during the period on positions that existed at December 31, 2010 | 4,674 | |
| Unrealized gain (loss) on new positions entered during the period and still existing at September 30, 2011 | 10,876 | |
| Realized (gain) loss on positions that existed at December 31, 2010 and were settled during the period | (18,121 |) |
| Change in cash collateral | 5,067 | |
| Unrealized gain (loss) on positions that existed at December 31, 2010 and still exist at September 30, 2011 | (9,059 |) |
| Total fair value of marketing positions at September 30, 2011 | \$16,855 | (a) |

(a) The fair value of marketing positions consists of derivative assets and derivative liabilities held at fair value in accordance with accounting standards for fair value measurements and market value adjustments to natural gas inventory that has been designated as a hedged item as part of a fair value hedge in accordance with accounting standards for derivatives and hedges, as follows (in thousands):

| | September 30, 2011 | June 30, 2011 | March 31, 2011 | December 31, 2010 | September 30, 2010 |
|---|-----------------------|------------------|-------------------|----------------------|-----------------------|
| Net derivative assets | \$9,515 | \$27,415 | \$11,518 | \$28,524 | \$51,734 |
| Cash collateral | 9,026 | 1,250 | 2,984 | 3,958 | (7,365 |
| Market adjustment recorded in material, supplies and fuel | (1,686 |) (585 |) 316 | (9,064 |) (18,716 |
| Total fair value of energy marketing positions marked-to-market | \$16,855 | \$28,080 | \$14,818 | \$23,418 | \$25,653 |

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in accounting standards for fair value measurements and disclosures. See Note 3 of the Notes to Consolidated Financial Statements in our 2010 Annual Report on Form 10-K and Note 12 and Note 13 of the accompanying Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

The sources of fair value measurements were as follows (in thousands):

| Source of Fair Value of Energy Marketing Positions | Maturities | | Total Fair Value |
|--|------------------|-------------|------------------|
| | Less than 1 year | 1 - 2 years | |
| Cash collateral | \$8,704 | \$322 | \$9,026 |
| Level 1 | — | — | — |
| Level 2 | 191 | 4,749 | 4,940 |
| Level 3 | (440 |) 5,015 | 4,575 |
| Market value adjustment for inventory (see footnote (a) above) | (1,686 |) — | (1,686 |
| | | |) |
| Total fair value of our energy marketing positions | \$6,769 | \$10,086 | \$16,855 |

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative under accounting for derivatives and hedging. Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas, crude oil and coal marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting standards for derivatives generally do not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our marketing positions are fully economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements. The table below references non-GAAP measures that quantify these positions.

The following table presents a reconciliation of our September 30, 2011 marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market (in thousands):

| | |
|--|----------|
| Fair value of our marketing positions marked-to-market in accordance with GAAP (see footnote (a) above) | \$16,855 |
| Market value adjustments for inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP | (6,722 |
| |) |
| Fair value of all forward positions (non-GAAP) | 10,133 |
| Cash collateral included in GAAP marked-to-market fair value | (9,026 |
| |) |
| Fair value of all forward positions excluding cash collateral (non-GAAP) * | \$1,107 |

* This measure is a non-GAAP financial measure. This measure is presented because we believe it provides a more comprehensive view to our investors of our energy trading activities and thus a better understanding of these activities than would be presented by a GAAP measure alone.

Except as discussed above, there have been no material changes in market risk from those reported in our 2010 Annual Report on Form 10-K filed with the SEC. For more information on market risk, see Part II, Items 7 and 7A. in our 2010 Annual Report on Form 10-K, and Note 12 of the Notes to our Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2011, 2012 and 2013 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at September 30, 2011 were as follows:

Natural Gas

| Location | Transaction Date | Hedge Type | Term | Volume (MMBtu/day) | Price |
|------------------|------------------|------------|---------------|-----------------------|--------|
| San Juan El Paso | 10/23/2009 | Swap | 10/11 - 12/11 | 2,500 | \$6.23 |
| NWR | 10/23/2009 | Swap | 10/11 - 12/11 | 1,500 | \$6.12 |
| AECO | 12/11/2009 | Swap | 10/11 - 12/11 | 500 | \$6.27 |
| CIG | 12/11/2009 | Swap | 10/11 - 12/11 | 1,500 | \$6.03 |
| San Juan El Paso | 12/11/2009 | Swap | 10/11 - 12/11 | 5,000 | \$6.15 |
| San Juan El Paso | 1/8/2010 | Swap | 01/12 - 03/12 | 2,500 | \$6.38 |
| NWR | 1/8/2010 | Swap | 01/12 - 03/12 | 1,500 | \$6.47 |
| AECO | 1/8/2010 | Swap | 01/12 - 03/12 | 500 | \$6.32 |
| CIG | 1/8/2010 | Swap | 01/12 - 03/12 | 1,500 | \$6.43 |
| San Juan El Paso | 1/25/2010 | Swap | 01/12 - 03/12 | 5,000 | \$6.44 |
| San Juan El Paso | 3/19/2010 | Swap | 04/12 - 06/12 | 7,000 | \$5.27 |
| CIG | 3/19/2010 | Swap | 04/12 - 06/12 | 1,500 | \$5.17 |
| NWR | 3/19/2010 | Swap | 04/12 - 06/12 | 1,500 | \$5.20 |
| AECO | 3/19/2010 | Swap | 04/12 - 06/12 | 250 | \$5.15 |
| San Juan El Paso | 6/28/2010 | Swap | 07/12 - 09/12 | 3,500 | \$5.19 |
| NWR | 6/28/2010 | Swap | 07/12 - 09/12 | 1,500 | \$5.01 |
| CIG | 6/28/2010 | Swap | 07/12 - 09/12 | 1,500 | \$4.98 |
| CIG | 2/18/2011 | Swap | 10/12 - 12/12 | 500 | \$4.42 |
| San Juan El Paso | 2/18/2011 | Swap | 10/12 - 12/12 | 2,500 | \$4.46 |
| NWR | 2/18/2011 | Swap | 10/12 - 12/12 | 1,000 | \$4.44 |
| San Juan El Paso | 4/19/2011 | Swap | 07/12 - 09/12 | 2,000 | \$4.45 |
| San Juan El Paso | 4/19/2011 | Swap | 10/12 - 12/12 | 2,000 | \$4.62 |
| San Juan El Paso | 4/19/2011 | Swap | 01/13 - 03/13 | 2,500 | \$5.03 |
| San Juan El Paso | 4/19/2011 | Swap | 04/13 - 06/13 | 2,500 | \$4.64 |
| San Juan El Paso | 6/6/2011 | Swap | 01/13 - 03/13 | 2,500 | \$5.18 |

Crude Oil

| Location | Transaction Date | Hedge Type | Term | Volume (Bbls/month) | Price |
|----------|------------------|------------|---------------|------------------------|----------|
| NYMEX | 10/9/2009 | Swap | 10/11 - 12/11 | 5,000 | \$79.35 |
| NYMEX | 10/23/2009 | Put | 10/11 - 12/11 | 5,000 | \$75.00 |
| NYMEX | 11/19/2009 | Swap | 10/11 - 12/11 | 5,000 | \$87.50 |
| NYMEX | 1/8/2010 | Put | 10/11 - 12/11 | 6,000 | \$75.00 |
| NYMEX | 1/8/2010 | Put | 01/12 - 03/12 | 5,000 | \$75.00 |
| NYMEX | 1/25/2010 | Swap | 01/12 - 03/12 | 5,000 | \$83.30 |
| NYMEX | 2/26/2010 | Swap | 01/12 - 03/12 | 5,000 | \$83.80 |
| NYMEX | 3/19/2010 | Swap | 01/12 - 03/12 | 5,000 | \$83.80 |
| NYMEX | 3/19/2010 | Swap | 04/12 - 06/12 | 5,000 | \$84.00 |
| NYMEX | 3/31/2010 | Put | 04/12 - 06/12 | 5,000 | \$75.00 |
| NYMEX | 5/13/2010 | Swap | 04/12 - 06/12 | 5,000 | \$87.85 |
| NYMEX | 6/28/2010 | Swap | 07/12 - 09/12 | 5,000 | \$83.80 |
| NYMEX | 8/17/2010 | Swap | 04/12 - 06/12 | 3,000 | \$82.60 |
| NYMEX | 8/17/2010 | Swap | 07/12 - 09/12 | 5,000 | \$82.85 |
| NYMEX | 9/16/2010 | Swap | 07/12 - 09/12 | 5,000 | \$84.60 |
| NYMEX | 11/9/2010 | Swap | 10/12 - 12/12 | 5,000 | \$91.10 |
| NYMEX | 1/6/2011 | Swap | 10/12 - 12/12 | 5,000 | \$93.40 |
| NYMEX | 1/20/2011 | Swap | 01/13 - 03/13 | 5,000 | \$94.20 |
| NYMEX | 2/17/2011 | Swap | 10/12 - 03/13 | 5,000 | \$97.85 |
| NYMEX | 3/4/2011 | Swap | 07/11 - 12/11 | 5,000 | \$106.10 |
| NYMEX | 3/4/2011 | Swap | 01/12 - 12/12 | 2,000 | \$104.60 |
| NYMEX | 3/4/2011 | Swap | 01/13 - 03/13 | 3,000 | \$103.35 |
| NYMEX | 4/20/2011 | Swap | 07/12 - 06/13 | 2,000 | \$106.80 |
| NYMEX | 6/3/2011 | Swap | 04/13 - 06/13 | 5,000 | \$100.90 |
| NYMEX | 7/27/2011 | Swap | 04/13 - 06/13 | 5,000 | \$102.72 |
| NYMEX | 7/27/2011 | Swap | 07/13 - 12/13 | 5,000 | \$102.75 |

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. As of September 30, 2011, we had \$150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 5.25 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheets.

We also have interest rate swaps with a notional amount of \$250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges and the mark-to-market value was recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the Condensed Consolidated Statement of Income. For the three months and nine months ended

September 30, 2011, we recorded pre-tax unrealized mark-to-market losses of \$38.2 million and \$40.6 million, respectively. For the three months and nine months ended September 30, 2010, we recorded pre-tax unrealized mark-to-market losses of \$13.7 million and \$41.7 million, respectively. These swaps are 7.25 and 17.25 year swaps which have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are \$225 million and \$250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the stated termination dates.

Further details of the swap agreements are set forth in Note 12 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

As of September 30, 2011, December 31, 2010 and September 30, 2010, our interest rate swaps and related balances were as follows (dollars in thousands):

| | September 30, 2011 | | December 31, 2010 | | September 30, 2010 | |
|--|--------------------------------|-----------------------------------|--------------------------------|-----------------------------------|--------------------------------|-----------------------------------|
| | Designated Interest Rate Swaps | Dedesignated Interest Rate Swaps* | Designated Interest Rate Swaps | Dedesignated Interest Rate Swaps* | Designated Interest Rate Swaps | Dedesignated Interest Rate Swaps* |
| Current notional amount | \$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 | 5.25 | 0.25 | 6.00 | 1.00 | 6.25 | 0.25 |
| Derivative liabilities, current | \$6,724 | \$94,588 | \$6,823 | \$53,980 | \$6,901 | \$80,450 |
| Derivative liabilities, non-current | \$21,108 | \$— | \$14,976 | \$— | \$21,518 | \$— |
| Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets | \$(27,832) | \$— | \$(21,799) | \$— | \$(28,419) | \$— |
| Pre-tax (loss) gain included in Condensed Consolidated Statements of Income | \$— | \$(40,608) | \$— | \$(15,193) | \$— | \$(41,663) |
| Cash collateral receivable (payable) included in accounts receivable | \$— | \$— | \$— | \$— | \$— | \$25,000 |

* Maximum terms in years for our de-designed interest rate swaps reflect the amended mandatory early termination dates. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. When extended annually, de-designated swaps totaling \$100 million terminate in 7.25 years and de-designated swaps totaling \$150 million terminate in 17.25 years.

Based on September 30, 2011 market interest rates and balances for our \$150 million notional interest rate swaps, a loss of approximately \$6.7 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next 12 months 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 September 30, 2011. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

There have been no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2011 that have materially affected or are reasonably likely to materially affect our internal control over

financial reporting.

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BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2010 Annual Report on Form 10-K and Note 15 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 15 is incorporated by reference into this item.

ITEM 1A. Risk Factors

Except as described below, there are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2010.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our oil and natural gas properties. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the well-bore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide the federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process.

Certain states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In the event federal, state, local or municipal legal restrictions are adopted in areas where we are conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such regulations that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from utilizing fracture stimulation and effectively preclude the drilling of wells.

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, 2011 - July 31, 2011 | — | \$— | — | — |
| August 1, 2011 - August 31, 2011 | 3,850 | \$28.91 | — | — |
| September 1, 2011 - September 30, 2011 | — | \$— | — | — |
| Total | 3,850 | \$28.91 | — | — |

(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 5. Other Information

Mine Safety and Health Administration Safety Data

Safety is a core value at Black Hills Corporation and at each of its subsidiary operations. We have in place a comprehensive safety program that includes extensive health and safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

Under the recently enacted Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operations, consisting of WRDC, are subject to regulation by the federal Mine Safety and Health Administration (“MSHA”) under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present the following information regarding certain mining safety and health matters for the three month period ended September 30, 2011. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;

Total number of orders issued under section 104(b) of the Mine Act;

Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;

Total number of imminent danger orders issued under section 107(a) of the Mine Act; and

Total dollar value of proposed assessments from MSHA under the Mine Act.

During the three months ended September 30, 2011, WRDC (i) was not assessed any Mine Act section 110(b)(2) penalties for failure to correct the subject matter of a Mine Act section 104(a) citation within the specified time period, which failure was deemed flagrant (i.e., a reckless or repeated failure to make reasonable efforts to eliminate a known violation that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury); (ii) did not receive any Mine Act section 107(a) imminent danger orders to immediately remove miners; or (iii) did not receive any MSHA written notices under Mine Act section 104(e) of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern. In addition, there were no fatalities at the mine during the three months ended September 30, 2011.

The table below sets forth the total number of section 104 citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments, received during the three months ended September 30, 2011 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for WRDC, our only mining complex. All citations were abated within 24 hours of issue.

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| Mine Act Section 104 Significant and Substantial Citations | Mine Act Section 104(b) Orders | Mine Act Section 104(d) Citations and Orders | Mine Act Section 107(a) Imminent Danger Orders | Total Dollar Value of Proposed MSHA Assessments | Number of Legal Actions Pending Before the Federal Mining Safety and Health Review Commission |
|--|--------------------------------|--|--|---|---|
| — | — | — | — | \$32,096 | 1 |

ITEM 6. Exhibits

| | |
|--------------|---|
| Exhibit 10 | First Amendment to the Credit Agreement dated December 15, 2010 among Black Hills Corporation, as Borrower, JPMorgan Chase Bank, N.A., in its capacity as agent for the Banks and as a Bank, and each of the other Banks (filed as Exhibit 10 to the Company's Form 8-K filed on October 3, 2011 and incorporated by reference herein). |
| 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. |
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| Exhibit 101 | Financials for XBRL Format |

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

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

Dated: November 4, 2011

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EXHIBIT INDEX

| Exhibit Number | Description |
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