BLACK HILLS CORP /SD/
Form 10-Q
May 10, 2011

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2011.

OR

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

Commission File Number 001-31303

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

Registrant's telephone number (605) 721-1700

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

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

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

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

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

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

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

Class	Outstanding as of	April 29, 2011
Common stock, $1.00 par value	39,409,489	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)
Aquila	Aquila, Inc.
ASC	Accounting Standards Codification
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
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 that was formerly known as Black Hills Energy, Inc.
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	Commodities Futures and 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
De-designated interest rate swaps	The $250.0 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

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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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Forward Agreement	Equity Forward Agreement with J. P. Morgan connected to a public offering of 4,000,000 million shares of Black Hills Corporation common stock
GAAP	Generally Accepted Accounting Principles
Global Settlement	Global 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
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
MDU	MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
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 March 31,	
	2011	2010
	(in thousands, except per share amounts)	
Operating revenues:		
Utilities	$374,696	$388,666
Non-regulated energy	28,604	37,834
Total operating revenues	403,300	426,500
Operating expenses:		
Utilities -		
Fuel, purchased power and cost of gas sold	210,511	236,314
Operations and maintenance	67,409	65,034
Gain on sale of operating assets	—	(2,683)
Non-regulated energy operations and maintenance	29,211	22,960
Depreciation, depletion and amortization	31,987	28,395
Taxes - property, production and severance	8,218	6,477
Other operating expenses	251	301
Total operating expenses	347,587	356,798
Operating income	55,713	69,702
Other income (expense):		
Interest charges -		
Interest expense (including amortization of debt issuance costs, premium and discount, realized settlements on interest rate swaps)	(29,735)	(25,120)
Allowance for funds used during construction - borrowed	3,363	3,148
Capitalized interest	2,434	206
Interest rate swaps - unrealized (loss) gain	5,465	(3,035)
Interest income	560	246
Allowance for funds used during construction - equity	295	2,028
Other income, net	731	418
Total other income (expense)	(16,887)	(22,109)
Income (loss) from continuing operations before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	38,826	47,593
Equity in earnings (loss) of unconsolidated subsidiaries	993	317
Income tax benefit (expense)	(12,909)	(16,476)
Net income (loss)	$26,910	$31,434
Weighted average common shares outstanding:		
Basic	39,059	38,848

Diluted	39,761	39,009
Total earnings (loss) per share - basic	$0.69	$0.81
Total earnings (loss) per share - diluted	$0.68	$0.81
Dividends paid per share of common stock	$0.365	$0.360

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)

	March 31, 2011 (in thousands)	December 31, 2010	March 31, 2010
ASSETS			
Current assets:			
Cash and cash equivalents	$44,016	$32,438	$136,023
Restricted cash	3,406	4,260	27,215
Accounts receivable, net	306,070	328,811	242,189
Materials, supplies and fuel	69,341	139,677	91,111
Derivative assets, current	49,295	56,572	54,773
Income tax receivable, net	23,665	—	—
Deferred income tax assets, current	18,362	17,113	5,610
Regulatory assets, current	36,834	66,429	42,876
Other current assets	60,804	25,571	26,189
Total current assets	611,793	670,871	625,986
Investments	17,088	17,780	18,466
Property, plant and equipment	3,461,559	3,359,762	3,045,126
Less accumulated depreciation and depletion	(889,031)	(864,329)	(830,423)
Total property, plant and equipment, net	2,572,528	2,495,433	2,214,703
Other assets:			
Goodwill	354,831	354,831	353,734
Intangible assets, net	4,011	4,069	4,248
Derivative assets, non-current	5,135	9,260	5,877
Regulatory assets, non-current	140,735	138,405	117,561
Other assets, non-current	20,907	20,860	18,064
Total other assets	525,619	527,425	499,484
TOTAL ASSETS	$3,727,028	$3,711,509	$3,358,639

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)

	March 31, 2011	December 31, 2010	March 31, 2010
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$217,559	$279,069	$194,342
Accrued liabilities	141,184	170,301	140,939
Derivative liabilities, current	91,139	79,167	68,834
Accrued income taxes, net	—	779	10,568
Regulatory liabilities, current	15,004	3,943	9,850
Notes payable	287,000	249,000	223,000
Current maturities of long-term debt	4,254	5,181	24,426
Total current liabilities	756,140	787,440	671,959
Long-term debt, net of current maturities	1,184,830	1,186,050	993,514
Deferred credits and other liabilities:			
Deferred income tax liability, non-current	303,647	277,136	270,079
Derivative liabilities, non-current	15,554	21,361	12,081
Regulatory liabilities, non-current	90,923	84,611	44,788
Benefit plan liabilities	128,170	124,709	144,199
Other deferred credits and other liabilities	134,617	129,932	114,021
Total deferred credits and other liabilities	672,911	637,749	585,168
Stockholders' equity:			
Common stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized;			
Issued 39,434,304; 39,280,048 and 39,178,067 shares, respectively	39,434	39,280	39,178
Additional paid-in capital	601,021	598,805	593,589
Retained earnings	498,614	486,075	491,202
Treasury stock at cost – 26,075; 10,962 and 4,284 shares, respectively	(762)	(309)	(112)
Accumulated other comprehensive loss	(25,160)	(23,581)	(15,859)
Total stockholders' equity	1,113,147	1,100,270	1,107,998
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,727,028	$3,711,509	$3,358,639

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)

	Three Months Ended March 31,	
	2011	2010
Operating activities:	(in thousands)	
Net income (loss)	$26,910	$31,434
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	31,987	28,395
Derivative fair value adjustments	9,662	(1,579)
Gain on sale of operating assets	—	(2,683)
Stock compensation	2,370	989
Unrealized mark-to-market loss (gain) on interest rate swaps	(5,465)	3,035
Deferred income taxes	25,679	3,492
Equity in (earnings) loss of unconsolidated subsidiaries	(993)	(317)
Allowance for funds used during construction - equity	(295)	(2,028)
Employee benefit plans	3,642	3,940
Other adjustments	(1,599)	2,382
Change in operating assets and liabilities:		
Materials, supplies and fuel	79,717	21,755
Accounts receivable and other current assets	(35,605)	24,044
Accounts payable and other current liabilities	(73,302)	(24,716)
Regulatory assets	33,966	3,277
Regulatory liabilities	9,984	2,834
Other operating activities	4,613	(5,335)
Net cash provided by operating activities	111,271	88,919
Investing activities:		
Property, plant and equipment additions	(122,544)	(81,290)
Proceeds from sale of ownership interest in operating assets	—	6,105
Other investing activities	786	(2,865)
Net cash used in investing activities	(121,758)	(78,050)
Financing activities:		
Dividends paid	(14,371)	(14,089)
Common stock issued	605	1,522
Short-term borrowings - issuances	210,000	108,500
Short-term borrowings - repayments	(172,000)	(50,000)
Long-term debt - repayments	(2,155)	(33,217)
Other financing activities	(14)	(463)
Net cash provided by (used in) financing activities	22,065	12,253
Net change in cash and cash equivalents	11,578	23,122
Cash and cash equivalents beginning of period	32,438	112,901
Cash and cash equivalents end of period	$44,016	$136,023

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

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 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 (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 March 31, 2011, December 31, 2010 and March 31, 2010 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenues 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 months ended March 31, 2011 and our financial condition as of March 31, 2011, December 31, 2010, and March 31, 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 financial statements have been reclassified to conform to the current year presentation. Specifically, (a) the Company has reclassified revenue into two categories: utilities revenue and non-regulated revenues, (b) the categories of Fuel, purchased power and cost of gas sales and Operations and maintenance included in our Operating expenses have also been reclassified into utilities and non-regulated, and (c) the Taxes - property, production and severance line has been reclassified to show only those taxes. Any taxes other than income are now included in the respective utility or non-regulated operations and maintenance lines. 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 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 revenue and Fuel, purchased power and cost of gas sold of $15.8 million, in aggregate for the three months ended March 31, 2010, respectively. As such, the condensed consolidated financial statements have been restated for the correction of this error. The error did not have an impact on our gross margin, net income, total assets or cash flows.

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

Recently Adopted Accounting Standards

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 are 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 requires additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 13.

Recently Issued Accounting Standards and Legislation

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 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 accounting implications of the PPACA as related regulations and interpretations become available.

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, potentially including utilities, and it 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 over the next several months to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank, and we will continue to evaluate the impact as these rules become available.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three Months Ended

	March 31, 2011	March 31, 2010
	(in thousands)	
Non-cash investing activities—		
Property, plant and equipment acquired with accrued liabilities	$32,419	$23,473
Cash (paid) refunded during the period for—		
Interest (net of amounts capitalized)	$(11,817)	$(10,182)
Income taxes, net	$(24)	$44

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(4) MATERIALS, SUPPLIES AND FUEL

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

	March 31, 2011	December 31, 2010	March 31, 2010
Materials and supplies	$34,341	$31,749	$32,200
Fuel - Electric Utilities	9,307	9,687	9,028
Natural gas in storage — Gas Utilities	2,199	21,691	4,868
Gas and oil held by Energy Marketing*	23,494	76,550	45,015
Total materials, supplies and fuel	$69,341	$139,677	$91,111

* As of March 31, 2011, December 31, 2010 and March 31, 2010, market adjustments related to natural gas held by Energy Marketing and recorded in inventory as part of fair value hedge transactions were $0.3 million, $(9.1) million and $(11.0) million, respectively (see Note 12 for further discussion of Energy Marketing trading activities).

(5) ACCOUNTS RECEIVABLE

Trade Accounts Receivable

Our Accounts receivable represents primarily customer trade accounts at our Electric Utilities, Gas Utilities and counterparty trade accounts at our Energy Marketing segment. This balance fluctuates primarily due to the seasonality of our Gas Utilities and volumes and commodity prices at our Energy Marketing segment. We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade accounts receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit-worthiness, the age of the accounts receivable balances and current economic conditions that may affect our ability to collect.

Following is a summary of receivables (in thousands):

March 31, 2011	Accounts Receivable, Trade	Unbilled Revenues	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$46,077	$16,196	$62,273	$(728)	$61,545
Gas	58,665	21,620	80,285	(1,763)	78,522
Oil and Gas	7,503	—	7,503	(161)	7,342
Coal Mining	982	—	982	—	982
Energy Marketing	154,660	—	154,660	(114)	154,546
Power Generation	2,050	—	2,050	—	2,050
Corporate	1,083	—	1,083	—	1,083
Total	$271,020	$37,816	$308,836	$(2,766)	$306,070

December 31, 2010	Accounts Receivable, Trade	Unbilled Revenues	Total Accounts Receivable	Less Allowance for Doubtful Accounts	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	12,247	—	12,247	—	12,247
Total	$271,226	$59,948	$331,174	$(2,363)	$328,811

March 31, 2010	Accounts Receivable, Trade	Unbilled Revenues	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$45,466	$13,415	$58,881	$(1,346)	$57,535
Gas	60,076	19,977	80,053	(2,877)	77,176
Oil and Gas	6,144	—	6,144	—	6,144
Coal Mining	1,698	—	1,698	—	1,698
Energy Marketing	99,738	—	99,738	(1,008)	98,730
Power Generation	569	—	569	—	569
Corporate	337	—	337	—	337
Total	$214,028	$33,392	$247,420	$(5,231)	$242,189

Income Tax Receivable

Income tax receivable is primarily comprised of the refund (including an estimate of after-tax interest income) to be received as a result of the settlement reached with IRS in mid-2010 and finalized in early 2011 and estimated payments made at the federal, state, and foreign levels. With respect to the estimated payments, they relate to multiple prior tax years and were included in taxes payable at both March 31, 2010 and December 31, 2010.

(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 March 31, 2011, we were in compliance with these covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

Revolving Credit Facility

In April 2010, we entered into a new $500.0 million Revolving Credit Facility expiring April 14, 2013. The facility contains an accordion feature which allows us to, with the consent of the administrative agent, increase the capacity of the facility to $600.0 million. This facility can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively at March 31, 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 of $4.7 million are being amortized over the term of the facility and the amortization expense is included in Interest expense on the accompanying Condensed Consolidated Statements of Income as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Amortization Expense	$473	$—

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 March 31, 2011.

	Actual	Covenant Requirement
Consolidated Net Worth	$1,113	$873
Recourse leverage ratio	57.8 %	65.0 %

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Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year $250.0 million committed credit facility. The facility contains an accordion feature which allows Enserco, with the consent of the administrative agent, to increase commitments under the facility to $350.0 million. Maximum borrowings under the facility are subject to a sub-limit 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%. The facility covenants include tangible net worth, net working capital and realized net working capital requirements. Enserco was in compliance with the covenants of this facility as of March 31, 2011.

At March 31, 2011, $147.1 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding.

Deferred financing costs of $2.1 million were recorded for the Enserco Credit Facility and are being amortized over the term of the facility. Amortization of deferred financing costs included in Interest expense on the accompanying Condensed Consolidated Statements of Income was as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Amortization expense	$268	$533

Corporate Term Loan

In December 2010, we entered into a one-year $100.0 million term loan (the "Loan") with J.P. Morgan and Union Bank due in December 2011. The cost of borrowing under the Loan was based on a spread of 137.5 basis points over LIBOR (1.69% at March 31, 2011). The covenants are substantially the same as those which are included in the Revolving Credit Facility. We were in compliance with these covenants as of March 31, 2011.

(7) EARNINGS PER SHARE

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

Period Ended March 31, 2011	Three Months	
	Income	Average Shares
Net income	$ 26,910	39,059
Dilutive effect of:		
Restricted stock	—	132
Options	—	17
Forward Equity Issuance	—	460
Other	—	93
Diluted earnings	$ 26,910	39,761
Diluted earnings per share	$ 0.68	

Period Ended March 31, 2010	Three Months	
	Income	Average Shares
Net income	$31,434	38,848
Dilutive effect of:		
Restricted stock	—	89
Options	—	—
Other	—	72
Diluted earnings	$31,434	39,009
Diluted earnings per share	$0.81	

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

	Three Months Ended March 31,	
	2011	2010
Options to purchase common stock	83	264
Restricted stock	7	—
	90	264

(8) COMPREHENSIVE INCOME (LOSS)

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

	Three Months Ended March 31, 2011	
Net income		$26,910
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges	$(3,785)	
Taxes	1,637	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		(2,148)
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$861	
Taxes	(292)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		569
Comprehensive income		$25,331

		Three Months Ended March 31, 2010
Net income		$31,434
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments	$19	
Taxes	(7)	
Minimum pension liability adjustments, net of tax		12
Fair value adjustment on derivatives designated as cash flow hedges	$2,007	
Taxes	(591)	
Fair value adjustment on derivatives designated as cash flow hedges, net of tax		1,416
Reclassification adjustments on cash flow hedges settled and included in net income (loss)	$2,938	
Taxes	(1,061)	
Reclassification adjustments on cash flow hedges settled and included in net income (loss), net of tax		1,877
Comprehensive income		$34,739

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

	March 31, 2011	December 31, 2010	March 31, 2010
Derivatives designated as cash flow hedges	$(14,016)	$(12,437)	$(6,182)
Employee benefit plans	(11,142)	(11,142)	(9,624)
Amount from equity-method investees	(2)	(2)	(53)
Total	$(25,160)	$(23,581)	$(15,859)

(9) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the first three months of 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. Actual shares are not issued until the end of the performance plan period (December 31, 2013). 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 the 2010 short-term incentive compensation plan during the three months ended March 31, 2011. Pre-tax compensation cost related to the awards was approximately $0.4 million, which was accrued for in 2010.

- We granted 125,963 restricted common shares during the three months ended March 31, 2011. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $3.8 million will be recognized over the three-year vesting period.

- 2,500 stock options were exercised during the three months ended March 31, 2011 at a weighted-average exercise price of $30.81 per share which provided $0.1 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended March 31, 2011 and 2010 was $2.4 million and $1.8 million, respectively.

As of March 31, 2011, total unrecognized compensation expense related to non-vested stock awards was $11.0 million and is expected to be recognized over a weighted-average period of 2.2 years.

Dividend Reinvestment and Stock Purchase Plan

We have a 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 25,026 new shares at a weighted-average price of $31.07 during the three months ended March 31, 2011. At March 31, 2011, 164,667 shares of unissued common stock were available for future offering under the DRIP Plan.

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% of aggregate consolidated net income, if positive, since January 1, 2005. As of March 31, 2011, we were in compliance with the above 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 shareholders 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 March 31, 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 March 31, 2011, the restricted net assets at our Utilities Group were approximately $193.7 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 March 31, 2011 were $86.2 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.

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Forward Equity Issuance

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").

Based on the closing Black Hills Corporation common stock price of $33.44 on March 31, 2011, and the forward price on the date for the initial equity forward of $27.95 and over-allotment shares of $27.95, the fair value net cash settlement of the 4,000,000 equity forward instrument and 413,519 over-allotment shares was approximately $24.2 million. The Forward Agreements require a 60-day notice prior to settlement for cash or net share settlements. Forward prices and volume-weighted average market prices for the period between when notice is provided and settlement are used to calculate cash and net share settlement amounts.

We may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settle on any date up to maturity, for all or a portion of the equity forward shares. It is our intent to settle the equity forward with the physical delivery of shares in the fourth quarter of 2011.

At March 31, 2011, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares to J.P. Morgan in exchange for cash of $123.4 million. Assuming required notices were given and actions taken, the forward instruments could have also been net settled at March 31, 2011 with delivery of cash of approximately $23.5 million or approximately 706,000 shares of common stock to J.P. Morgan.

(10) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Pension Plans"). One Pension Plan covers certain eligible employees of the following subsidiaries: Black Hills Service Company, Black Hills Power, WRDC and BHEP; one Pension Plan covers certain eligible employees of our subsidiary, Cheyenne Light, and the remaining 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 three Plans were as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Service cost	$1,355	$1,533
Interest cost	3,732	3,773
Expected return on plan assets	(4,239)	(3,623)
Prior service cost	25	305
Net loss	1,135	500
Net periodic benefit cost	$2,008	$2,488

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor three 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 March 31,	
	2011	2010
Service cost	$375	$377
Interest cost	542	611
Expected return on plan assets	(41)	(52)
Prior service cost (benefit)	(120)	(77)
Net loss (gain)	169	159
Net periodic benefit cost	$925	$1,018

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

Supplemental Non-qualified Defined Benefit Plans

Additionally, 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 March 31,	
	2011	2010
Service cost	$257	$171
Interest cost	324	321
Prior service cost	1	1
Net loss	127	71
Net periodic benefit cost	$709	$564

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 are expected to be made in the form of benefit payments. Contributions are as follows (in thousands):

	Contributions Made Three Months Ended March 31, 2011	Anticipated Contributions Remaining for 2011	Anticipated Contributions for 2012
Defined Benefit Pension Plans	$—	$550	$13,431
Non-Pension Defined Benefit Postretirement Healthcare Plans	$882	$2,647	$3,765
Supplemental Non-Qualified Defined Benefit Plans	$235	$707	$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 March 31, 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 supply 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 supply natural gas utility service 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 interest in the partnership which owned the Idaho facilities;

- 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 Balance Sheets was as follows (in thousands):

Three Months Ended March 31, 2011	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$144,430	$3,839	$10,249
Gas	230,266	—	19,263
Non-regulated Energy:			
Oil and Gas	17,906	—	(715)
Power Generation	687	6,933	1,186
Coal Mining	7,614	7,881	(1,298)
Energy Marketing	2,397	68	(2,641)
Corporate [(a)]	—	—	934
Intercompany eliminations	—	(18,721)	(68)
Total	$403,300	$—	$26,910

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Three Months Ended March 31, 2010	External Operating Revenues	Intercompany Operating Revenues [b]	Net Income (Loss)
Utilities:			
Electric	$144,387	$4,422	$9,852
Gas [c]	243,170	—	19,498
Non-regulated Energy:			
Oil and Gas	19,743	—	2,348
Power Generation	1,334	6,734	1,080
Coal Mining	6,882	7,098	1,346
Energy Marketing	9,856	(84)	2,193
Corporate [a]	—	—	(4,967)
Intercompany eliminations	—	(17,042)	84
Total	$425,372	$1,128	$31,434

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(a) Net income (loss) includes a $3.6 million net after-tax mark-to-market gain on interest rate swaps for the three months ended March 31, 2011 and a $2.0 million net after-tax mark-to-market loss on these same interest rate swaps for the three months ended March 31, 2010.
(b) Total Revenues have been restated to reflect elimination of intercompany activities previously not eliminated. See Note 1 for further discussion.
(c) Net income (loss) includes a $1.7 million after-tax gain on the sale of operating assets as a result of annexation proceedings by the City of Omaha, Nebraska.

Total assets	March 31, 2011	December 31, 2010	March 31, 2010
Utilities:			
Electric	$1,868,600	$1,834,019	$1,701,329
Gas	683,927	722,287	644,734
Non-regulated Energy:			
Oil and Gas	355,357	349,991	348,156
Power Generation	336,827	293,334	185,856
Coal Mining	94,416	96,962	82,776
Energy Marketing	293,544	314,930	324,478
Corporate	94,357	99,986	71,310
Total	$3,727,028	$3,711,509	$3,358,639

(12) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sector 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 transactions 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 in this Note along with Note 13.

Trading Activities

Energy Marketing

We have a natural gas, crude oil, coal, power and environmental marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the United States and Canada.

Contracts and other activities at our Energy Marketing operations are accounted for under 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 revenues 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 BHCRPP and further delineated in the Energy Marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee. Our trading contracts do not include credit risk-related contingent features that require us to maintain a specific credit rating.

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 March 31, 2011		Outstanding at December 31, 2010		Outstanding at March 31, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	649,523	19	399,128	22	240,400	19
Natural gas basis swaps sold	671,468	19	426,903	22	245,790	19
Natural gas fixed-for-float swaps purchased	199,897	30	135,005	33	87,161	20
Natural gas fixed-for-float swaps sold	196,305	19	150,803	22	99,233	22
Natural gas physical purchases	147,699	33	144,948	36	125,570	24
Natural gas physical sales	134,202	33	143,021	36	123,620	24
Natural gas futures purchased	13,570	13	—	—	—	—
Natural gas futures sold	12,050	2	—	—	—	—

	Outstanding at March 31, 2011		Outstanding at December 31, 2010		Outstanding at March 31, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	6,779	13	5,628	16	5,296	9
Crude oil physical sales	6,783	13	6,921	16	5,647	9
Crude oil swaps purchased	65	4	20	3	—	—
Crude oil swaps sold	275	4	240	4	94	2

	Outstanding at March 31, 2011		Outstanding at December 31, 2010	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of tons)				
Coal fixed-for-float swaps purchased	5,330	33	4,060	36
Coal fixed-for-float swaps sold	6,140	33	3,720	36
Coal physical purchases	25,575	45	24,634	48
Coal physical sales	11,065	33	9,046	36
Coal options purchased	2,970	45	2,835	48
Coal options sold	552	9	270	12

	Outstanding at March 31, 2011		Outstanding at December 31, 2010	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(in thousands of MWh):				
Power fixed-for-float swaps purchased	3,009	33	902	11
Power fixed-for-float swaps sold	3,008	33	902	11

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Derivatives and certain other marketing activities were marked to fair value and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Condensed Statements of Income were as follows (in thousands):

	March 31, 2011	December 31, 2010	March 31, 2010
Derivative assets, current	$41,482	$43,862	$40,541
Derivative assets, non-current	$3,951	$6,635	$2,409
Derivative liabilities, current	$31,167	$14,550	$17,733
Derivative liabilities, non-current	$(236)	$3,464	$(588)
Cash collateral receivable (payable) included in derivative assets/liabilities	$2,984	$3,958	$171
Unrealized gain	$11,518	$28,525	$25,634

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/loss on the Condensed Consolidated Statements of Income, effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of March 31, 2011, December 31, 2010 and March 31, 2010, the market adjustments recorded in Materials, supplies and fuel were $0.3 million, $(9.1) million and $(11.0) 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 is reported in earnings.

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

	March 31, 2011		December 31, 2010		March 31, 2010	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional*	487,500	5,974,800	424,500	6,821,800	565,500	10,142,050
Maximum terms in years **	1	0.25	0.25	0.25	0.25	0.75
Derivative assets, current	$108	$6,649	$248	$7,675	$2,816	$9,151
Derivative assets, non-current	$—	$975	$19	$2,606	$220	$3,248
Derivative liabilities, current	$4,688	$—	$3,814	$—	$2,655	$53
Derivative liabilities, non-current	$2,678	$157	$1,301	$—	$1,428	$—
Pre-tax accumulated other comprehensive income (loss) included in balance sheets	$(7,613)	$7,467	$(5,313)	$10,281	$(1,908)	$12,346
Earnings	$355	$—	$465	$—	$861	$—

* Crude oil in Bbls, gas in MMBtu.
** Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the timing of the hedged transaction and the corresponding settlement of the derivative instrument.

Based on March 31, 2011 market prices, a $1.6 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 change.

Gas Utilities - Gas Hedges

Our Gas Utilities segment purchases and 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 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 Consolidated Income Statements 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:

	Outstanding at March 31, 2011		Outstanding at December 31, 2010		Outstanding at March 31, 2010	
	Notional Amounts (MMBtus)	Latest Expiration (months)	Notional Amounts (MMBtus)	Latest Expiration (months)	Notional Amounts (MMBtus)	Latest Expiration (months)
Natural gas futures purchased	4,680,000	24	6,670,000	15	4,740,000	24
Natural gas options purchased	—	—	1,730,000	3	—	—

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

	March 31, 2011	December 31, 2010	March 31, 2010
Derivative assets, current	$1,056	$4,787	$1,943
Derivative assets, non-current	$209	$—	$—
Derivative liabilities, non-current	$—	$1,620	$324
Net unrealized gain (loss) included in regulatory assets	$(2,455)	$(8,030)	$(6,475)
Cash collateral receivable (payable) included in derivative assets/liabilities	$3,720	$10,355	$8,094
Option premium included in Derivative assets, current	$—	$842	$—

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):

	March 31, 2011		December 31, 2010		March 31, 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	5.75	0.75	6.00	1.00	6.75	0.75
Derivative liabilities, current	$6,769	$48,515	$6,823	$53,980	$6,571	$41,822
Derivative liabilities, non-current	$12,955	$—	$14,976	$—	$10,917	$—
Pre-tax accumulated other comprehensive gain (loss) included in Condensed Consolidated Balance Sheets	$(19,724)	$—	$(21,799)	$—	$(17,488)	$—
Pre-tax (loss) gain included in Condensed Consolidated Income Statements	$—	$5,465	$—	$(15,193)	$—	$(3,035)

* Maximum terms in years reflect the amended mandatory early termination dates of the seven and 17 year de-designated swaps. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date.

Based on March 31, 2011 market interest rates and balances related to our $150.0 million in designated interest rate swaps, a loss of approximately $6.8 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next 12 months as market interest rates change. Note 13 provides further information related to the $250 million notional swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Contracts

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.

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

	As of March 31, 2011		As of December 31, 2010		As of March 31, 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	$—	—
Canadian dollars sold	$8,000	1	$—	—	$—	—

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

	As of March 31, 2011	As of December 31, 2010	As of March 31, 2010
Fair Value	$(106)	$(143)	$—

We recognized the following gains and losses in Operating revenues on the accompanying Condensed Consolidated Statements of Income (in thousands):

	Three Months Ended March 31,	
	2011	2010
Unrealized foreign exchange gain (loss)	$(252)	$132
Realized foreign exchange gain (loss)	$338	$(141)

(13) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three 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 March 31, 2011				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives — Energy Marketing	$—	$181,201	$9,702	$(145,470)	$45,433
Commodity derivatives — Oil and Gas	—	7,626	106	—	7,732
Commodity derivatives — Utilities Group	—	(2,455)	—	3,720	1,265
Money market funds	9,050	—	—	—	9,050
Total	$9,050	$186,372	$9,808	$(141,750)	$63,480
Liabilities:					
Commodity derivatives — Energy Marketing	$—	$173,886	$5,396	$(148,457)	$30,825
Commodity derivatives — Oil and Gas	—	7,523	—	—	7,523
Foreign currency derivative	—	106	—	—	106
Interest rate swaps	—	68,239	—	—	68,239
Total	$—	$249,754	$5,396	$(148,457)	$106,693

	As of December 31, 2010				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives — Energy Marketing	$—	$166,405	$7,976	$(124,049)	$50,332
Commodity derivatives — Oil and Gas	—	10,281	266	—	10,547
Commodity derivatives — Utilities Group	—	(5,568)	—	10,355	4,787
Money market funds	8,050	—	—	—	8,050
Foreign currency derivative	—	166	—	—	166
Total	$8,050	$171,284	$8,242	$(113,694)	$73,882
Liabilities:					
Commodity derivatives — Energy Marketing	$—	$143,537	$2,463	$(128,007)	$17,993
Commodity derivatives — Oil and Gas	—	5,115	—	—	5,115
Commodity derivatives — Utilities Group	—	1,620	—	—	1,620
Foreign currency derivative	—	21	—	—	21
Interest rate swaps	—	75,779	—	—	75,779

Total	$—	$226,072	$2,463	$(128,007)	$100,528

	As of March 31, 2010				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives — Energy Marketing	$—	$214,788	$1,183	$(172,968)	$43,003
Commodity derivatives — Oil and Gas	—	14,127	1,255	—	15,382
Commodity derivatives — Utilities Group	—	(5,829)	—	8,094	2,265
Money market funds	9,000	—	—	—	9,000
Total	$9,000	$223,086	$2,438	$(164,874)	$69,650
Liabilities:					
Commodity derivatives — Energy Marketing	$—	$189,194	$1,143	$(173,139)	$17,198
Commodity derivatives — Oil and Gas	—	4,082	—	—	4,082
Commodity derivatives — Utilities Group	—	324	—	—	324
Interest rate swaps	—	59,311	—	—	59,311
Total	$—	$252,911	$1,143	$(173,139)	$80,915

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(a) Cash Collateral on deposit in margin accounts under master netting agreements at March 31, 2011, December 31, 2010 and March 31, 2010 totaled a net $6.7 million, $14.3 million and $8.3 million, respectively.

The following tables present the changes in level 3 recurring fair value for the three months ended March 31, 2011 and 2010, respectively (in thousands):

	Three Months Ended March 31, 2011 Commodity Derivatives
Balance as of beginning of period	$5,779
Unrealized losses	(6,199)
Unrealized gains	6,201
Purchases	—
Issuances	—
Settlements	(2,219)
Transfers into level 3 [(a)]	820
Transfers out of level 3[(b)]	31
Balances at end of period	$4,413
Changes in unrealized gains (losses) relating to instruments still held as of quarter-end	$(1,027)

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	Three Months Ended March 31, 2010 Commodity Derivatives
Balance as of beginning of period	$(556)
Unrealized losses	(1,215)
Unrealized gains	1,381
Purchases, issuance and settlements	(307)
Transfers into level 3 [(a)]	—
Transfers out of level 3[(b)]	1,992
Balances at end of period	$1,295
Changes in unrealized gains (losses) relating to instruments still held as of quarter-end	$1,745

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(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.

Gains and (losses) (realized and unrealized) for level 3 commodity derivatives totaling less than $(0.1) million and $0.3 million for the three months ended March 31, 2011 and 2010, respectively, are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income while less than $0.1 million and $(0.1) million was recorded through Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets for the three months ended March 31, 2011 and 2010, 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 $6.7 million, $14.3 million and $8.3 million on deposit in margin accounts at March 31, 2011, December 31, 2010, and March 31, 2010, respectively, to collateralize certain financial instruments, which is included in Derivative assets - current, Derivative assets - non-current and/or Derivative liabilities - 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 March 31, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$39	$131
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	97	289
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	6,769
Interest rate swaps	Derivative liabilities — non-current	—	12,955
Total derivatives designated as hedges		$136	$20,144
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$58,930	$10,346
Commodity derivatives	Derivative assets — non-current	26,674	21,539
Commodity derivatives	Derivative liabilities — current	156,557	198,015
Commodity derivatives	Derivative liabilities — non-current	1,453	4,052
Foreign currency derivatives	Derivative liabilities — current	—	106
Interest rate swap	Derivative liabilities — current	—	48,515
Total derivatives not designated as hedges		$243,614	$282,573

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
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	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 March 31, 2010

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$12,551	$732
Commodity derivatives	Derivative assets — non-current	19	—
Commodity derivatives	Derivative liabilities — current	—	193
Commodity derivatives	Derivative liabilities — non-current	—	20
Interest rate swaps	Derivative liabilities — current	—	6,571
Interest rate swaps	Derivative liabilities — non-current	—	10,918
Total derivatives designated as hedges		$12,570	$18,434
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$196,378	$161,518
Commodity derivatives	Derivative assets — non-current	19,881	14,023
Commodity derivatives	Derivative liabilities — current	8,884	29,234
Commodity derivatives	Derivative liabilities — non-current	519	1,731
Interest rate swaps	Derivative liabilities — current	—	41,822
Total derivatives not designated as hedges		$225,662	$248,328

Our derivative activities are discussed in Note 12. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income:

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):

		Three Months Ended March 31, 2011	
Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	
Commodity derivatives	Operating revenue	$(9,717	)
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	9,382	
		$(335	)

		Three Months Ended March 31, 2010	
Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	
Commodity derivatives	Operating revenue	$11,208	
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(10,747	)
		$461	

Cash Flow Hedges

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

Three Months Ended March 31, 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	$298	Interest expense	$(1,892)		$—
Commodity derivatives	(4,083)	Operating revenue	1,031	Operating revenue	—
Total	$(3,785)		$(861)		$—

Three Months Ended March 31, 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	$(2,074)	Interest expense	$(305)		$—
Commodity derivatives	6,581	Operating revenue	3,243	Operating revenue	(163)
Total	$4,507		$2,938		$(163)

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

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$(4,230)
Interest rate swaps - unrealized	Interest rate swaps — unrealized (loss) gain	5,465
Interest rate swaps - realized	Interest expense	(3,352)
Foreign currency contracts	Operating revenue	(249)
		$(2,366)

Derivatives Not Designated as Hedging Instruments

Three Months Ended

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	March 31, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$(2,659)
Interest rate swaps - unrealized	Interest rate swaps — unrealized (loss) gain	(3,035)
Interest rate swaps - realized	Interest expense	(3,317)
Foreign currency contracts	Operating revenue	—
		$(9,011)

(14) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments at March 31, 2011, December 31, 2010 and March 31, 2010 was as follows (in thousands):

	March 31, 2011		December 31, 2010		March 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents	$44,016	$44,016	$32,438	$32,438	$136,023	$136,023
Restricted cash	$3,406	$3,406	$4,260	$4,260	$27,215	$27,215
Derivative financial instruments - assets	$54,430	$54,430	$65,832	$65,832	$60,650	$60,650
Derivative financial instruments - liabilities	$106,693	$106,693	$100,528	$100,528	$80,915	$80,915
Notes payable	$287,000	$287,000	$249,000	$249,000	$223,000	$223,000
Long-term debt, including current maturities	$1,189,084	$1,260,539	$1,191,231	$1,290,519	$1,017,940	$1,102,574

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.

Restricted Cash

Restricted cash is primarily related to cash held in escrow as required by Black Hills Wyoming project financing agreements.

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 three 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 March 31, 2011, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Guarantees

As of December 31, 2010, the Company 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.

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 Utility 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 reported within the Electric Utilities segment, also 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 energy 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.

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Certain industries in which we operate are highly seasonal and revenues 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 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 months ended March 31, 2011 and 2010, and our financial condition as of March 31, 2011, December 31, 2010, and March 31, 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 58.

Results of Operations

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.

Executive Summary, Significant Events and Overview

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income for the three months ended March 31, 2011 was $26.9 million, or $0.68 per share, compared to Net income of $31.4 million, or $0.81 per share, reported for the same period in 2010. The 2011 Net income includes a $3.6 million non-cash after-tax unrealized mark-to-market gain on certain interest rate swaps. The 2010 Net income included a $2.0 million non-cash after-tax unrealized mark-to-market loss on these same interest rate swaps and a $1.7 million after-tax gain on sale of operating assets at Nebraska Gas.

	Three Months Ended March 31,	
	2011	2010
Operating Revenues *		
Utilities	$378,535	$391,979
Non-regulated Energy	43,486	51,563
Intercompany eliminations	(18,721)	(17,042)
	$403,300	$426,500
Net income (loss)		
Utilities	$29,512	$29,350
Non-regulated Energy	(3,536)	7,051
Corporate	934	(4,967)
	$26,910	$31,434

* 2010 Operating Revenues have been restated to eliminate inter-company revenues previously not eliminated. This change did not have an impact on our gross margin or net income.

Net income decreased $4.5 million for the three months ended March 31, 2011 reflecting the following:

Utilities

- A $0.4 million increase in Electric Utilities earnings;
- A $0.2 million decrease in the Gas Utilities earnings;

Non-regulated Energy

- A $3.1 million decrease in Oil and Gas earnings;
- A $2.6 million decrease in Coal Mining earnings;
- A $5.0 million decrease in Energy Marketing earnings;
- Power Generation earnings comparable to first quarter of 2010; and

Corporate

- A $5.9 million decrease in unallocated Corporate expenses.

Business Group highlights are as follows:

Utilities Group

- New and interim rates were implemented in five utility jurisdictions during 2010. Consequently, revenues have been positively impacted for rates that were not in effect in the prior period.

Utility	State	Effective Date	Annual Revenue Increase (in millions)	
Black Hills Power	SD	4/2010	$	15.2
Black Hills Power	WY	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

- Effective February 10, 2011 the IUB approved a settlement agreement for an increase in annual utility revenue of $3.4 million at Iowa Gas. Interim rates equal to a $2.6 million increase went into effect in June 2010;
- Construction of gas-fired generation to serve Colorado Electric customers is moving forward to start providing energy by the end of 2011. The 180 MW generation project is expected to cost approximately $227 million, of which $212.9 million has been expended through March 31, 2011;
- On April 28, 2011, Colorado Electric filed a request with the CPUC for a revenue increase of $40.2 million to recover costs 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 that is being replaced with the new

380 MW of gas-fired generation;

- On April 28, 2011, Black Hills Power filed a request for declaratory ruling from the SDPUC asking to confirm that a proposed 20 MW wind farm site near Belle Fourche, SD is reasonable and cost effective. This $38.0 million project would be owned by Black Hills Power and advance our progress toward the State of South Dakota's objective that 10% of all electricity sold be obtained from renewable, recycled and conserved energy resources by 2015;

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- On March 24, 2011, Colorado Electric filed a proposal with 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. Our share of this project is expected to cost approximately $27.0 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 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 third turbine; and

- Due to the annexation of an outlying suburb by the City of Omaha, Nebraska, Nebraska Gas sold assets serving approximately 3,000 customers to Metropolitan Utilities District on March 2, 2010. Nebraska Gas received $6.1 million in cash and recognized a $1.7 million after-tax gain on the sale of assets in the first quarter of 2010.

Non-regulated Energy Group

- Construction of gas-fired generation at Colorado IPP to serve a 20-year PPA with Colorado Electric is moving forward to start providing energy by the end of 2011. The 200 MW project is expected to cost approximately $260 million, of which $203.1 million has been expended through March 31, 2011.

Corporate

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $5.5 million for the first three months of 2011 compared to a $3.0 million non-cash unrealized mark-to-market loss on these swaps for the same period in 2010.

Following are additional details regarding the results of operations by business segment for our Utilities and Non-regulated Energy Groups, and Corporate activities.

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 and 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 March 31,	
	2011	2010
	(in thousands)	
Revenue — electric	$134,870	$132,768
Revenue — gas	13,399	16,041
Total revenue	148,269	148,809
Fuel and purchased power — electric	65,678	73,511
Purchased gas	8,396	11,191
Total fuel, purchased power and purchased gas	74,074	84,702
Gross margin — electric	69,192	59,257
Gross margin — gas	5,003	4,850
Total gross margin	74,195	64,107
Operations and maintenance	37,114	32,768
Depreciation and amortization	12,824	11,189
Total operating expenses	49,938	43,957
Operating income	24,257	20,150
Interest expense, net	(9,944)	(8,254)
Other income	409	2,125
Income tax expense	(4,473)	(4,169)
Net income	$10,249	$9,852

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

	Three Months Ended March 31,	
Revenue - electric (in thousands)	2011	2010
Residential:		
Black Hills Power	$17,170	$14,479
Cheyenne Light	8,071	7,925
Colorado Electric	20,436	19,416
Total Residential	45,677	41,820
Commercial:		
Black Hills Power	17,314	14,539
Cheyenne Light	12,543	12,456
Colorado Electric	16,585	15,690
Total Commercial	46,442	42,685
Industrial:		
Black Hills Power	5,764	4,637
Cheyenne Light	2,612	2,530
Colorado Electric	7,867	6,944
Total Industrial	16,243	14,111
Municipal:		
Black Hills Power	734	653
Cheyenne Light	391	231
Colorado Electric	2,936	1,687
Total Municipal	4,061	2,571
Contract Wholesale:		
Black Hills Power	4,620	6,718
Off-system Wholesale:		
Black Hills Power	6,953	8,716
Cheyenne Light	2,887	2,591
Colorado Electric [a]	—	7,333
Total Off-system Wholesale	9,840	18,640
Other:		
Black Hills Power	6,639	4,747
Cheyenne Light	689	912
Colorado Electric	659	564
Total Other	7,987	6,223
Total Revenue - electric	$134,870	$132,768

(a) Colorado Electric has an agreement with the CPUC which requires the deferral of off-system margins until a sharing mechanism is settled upon; due to the agreement Colorado Electric deferred $2.9 million in off-system revenue during the first quarter of 2011.

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	Three Months Ended March 31,	
Quantities Generated and Purchased (in MWh)	2011	2010
Generated —		
Coal-fired:		
Black Hills Power	437,838	430,573
Cheyenne Light	171,371	176,424
Colorado Electric	56,675	70,251
Total Coal-fired	665,884	677,248
Gas and Oil-fired:		
Black Hills Power	1,024	2,838
Cheyenne Light	—	—
Colorado Electric	—	—
Total Gas and Oil-fired	1,024	2,838
Total Generated:		
Black Hills Power	438,862	433,411
Cheyenne Light	171,371	176,424
Colorado Electric	56,675	70,251
Total Generated	666,908	680,086
Purchased —		
Black Hills Power	375,612	429,682
Cheyenne Light	197,169	192,857
Colorado Electric	482,785	541,202
Total Purchased	1,055,566	1,163,741
Total Generated and Purchased:		
Black Hills Power	814,474	863,093
Cheyenne Light	368,540	369,281
Colorado Electric	539,460	611,453
Total Generated and Purchased	1,722,474	1,843,827

	Three Months Ended March 31,	
Quantity Sold (in MWh)	2011	2010
Residential:		
Black Hills Power	174,400	174,535
Cheyenne Light	72,878	74,820
Colorado Electric	157,355	167,029
Total Residential	404,633	416,384
Commercial:		
Black Hills Power	178,237	184,438
Cheyenne Light	145,599	145,209
Colorado Electric	165,734	170,954
Total Commercial	489,570	500,601
Industrial:		
Black Hills Power	88,749	86,663
Cheyenne Light	40,828	40,759
Colorado Electric	83,909	84,510
Total Industrial	213,486	211,932
Municipal:		
Black Hills Power	8,302	8,226
Cheyenne Light	2,444	934
Colorado Electric	27,747	15,778
Total Municipal	38,493	24,938
Contract Wholesale:		
Black Hills Power [a]	89,959	168,465
Off-system Wholesale:		
Black Hills Power	242,156	231,047
Cheyenne Light	84,185	84,267
Colorado Electric [b]	78,503	159,775
Total Off-system Wholesale	404,844	475,089
Total Quantity Sold:		
Black Hills Power	781,803	853,374
Cheyenne Light	345,934	345,989
Colorado Electric	513,248	598,046
Total Quantity Sold	1,640,985	1,797,409
Losses and Company Use:		
Black Hills Power	32,671	9,719
Cheyenne Light	22,606	23,292
Colorado Electric	26,212	13,407
Total Losses and Company Use	81,489	46,418
Total Energy	1,722,474	1,843,827

(a) Decrease in 2011 MWh due to the termination of wholesale contracts with two previous wholesale power customers who acquired ownership interest in the Wygen III facility
(b) Includes 75,803 MWh at Colorado Electric for which $0.3 million gross margin was deferred in accordance with an agreement with the CPUC

Degree Days	Three Months Ended March 31, 2011		2010	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Black Hills Power	3,707	12 %	3,392	3 %
Cheyenne Light	3,123	— %	3,110	(1)%
Colorado Electric	2,781	5 %	2,777	5 %

	Electric Utilities Power Plant Availability Three Months Ended March 31, 2011	2010
Coal-fired plants	91.3 % (a)	94.0 % (b)
Other plants	98.6 %	99.7 %
Total availability	93.9 %	96.2 %

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(a) Reflects a planned major outage at the PacifiCorp-operated Wyodak plant.

(b) Reflects an unplanned 12 day outage at the PacifiCorp-operated Wyodak plant due to a collapsed scrubber vessel.

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 of these natural gas distribution operations:

	Three Months Ended March 31, 2011	2010
Revenue - gas (in thousands):		
Residential	$7,978	$9,513
Commercial	3,807	4,833
Industrial	1,276	1,458
Other	338	237
Total Revenue - gas	$13,399	$16,041
Gross Margin (in thousands):		
Residential	$3,388	$3,252
Commercial	1,212	1,217
Industrial	177	167
Other	226	214
Total Gross Margin	$5,003	$4,850
Volumes Sold (Dth):		
Residential	1,068,461	1,139,543
Commercial	623,723	661,118
Industrial	256,521	242,175
Total Volumes Sold	1,948,705	2,042,836

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income was $10.2 million for the three months ended March 31, 2011 compared to $9.9 million for the three months ended March 31, 2010 as a result of:

Gross margin: Gross margin increased $10.1 million primarily due to an increase of $12.0 million resulting from Black Hills Power and Colorado Electric rate cases implemented during 2010 and additional margins of $1.1 million related to recent transmission investments. These increases were partially offset by a decrease in off-system sales margin, lower retail quantities at Colorado Electric, and a decrease in revenue resulting from two previous wholesale power customers acquiring an ownership interest in Wygen III. Colorado Electric has an agreement with the CPUC which requires the deferral of off-system operating income until a sharing mechanism is settled upon. Due to the agreement Colorado Electric deferred $0.3 million in off-system operating income during the quarter.

Operations and maintenance: Operations and maintenance increased $4.3 million primarily due to additional costs associated with Wygen III which began commercial operation on April 1, 2010, an increase in employee compensation and benefit costs and increased corporate allocations.

Depreciation and amortization: Depreciation and amortization increased $1.6 million primarily due to commencement of depreciation on the Wygen III plant.

Interest expense, net: Interest expense, net increased $1.7 million primarily due to higher debt balances related to recent capital projects and higher interest rates.

Other income: Other income decreased $1.7 million primarily due to lower AFUDC-equity due to the placement of Wygen III into commercial operation.

Income tax expense: The effective tax rate for the Electric Utilities for the three months ended March 31, 2011 was comparable to the same period in the prior year.

Gas Utilities

	Three Months Ended March 31, 2011	2010
	(in thousands)	
Sales revenue:		
Natural gas — regulated	$223,032	$235,455
Other — non-regulated services	7,234	7,715
Total sales revenue	230,266	243,170
Cost of sales:		
Natural gas — regulated	149,503	163,427
Other — non-regulated services	3,626	4,018
Total cost of sales	153,129	167,445
Gross margin	77,137	75,725
Operations and maintenance	34,560	34,358
Gain on sale of operating assets	—	(2,683)
Depreciation and amortization	6,021	7,045
Total operating expenses	40,581	38,720
Operating income (loss)	36,556	37,005
Interest expense, net	(6,972)	(6,185)
Other income (expense)	25	(211)
Income tax benefit (expense)	(10,346)	(11,111)
Net income (loss)	$19,263	$19,498

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

	Three Months Ended March 31,	
Sales Revenue (in thousands)	2011	2010
Residential:		
Colorado	$22,986	$22,852
Nebraska	58,399	57,094
Iowa	47,431	48,679
Kansas	27,953	33,344
Total Residential	156,769	161,969
Commercial:		
Colorado	4,633	4,989
Nebraska	19,918	21,410
Iowa	20,883	22,789
Kansas	9,296	11,250
Total Commercial	54,730	60,438
Industrial:		
Colorado	115	44
Nebraska	173	1,505
Iowa	737	911
Kansas	1,120	787
Total Industrial	2,145	3,247
Transportation:		
Colorado	328	281
Nebraska	4,359	4,649
Iowa	1,325	1,200
Kansas	2,067	1,938
Total Transportation	8,079	8,068
Other:		
Colorado	31	27
Nebraska	608	612
Iowa	126	444
Kansas	544	650
Total Other	1,309	1,733
Total Regulated	223,032	235,455
Non-regulated Services	7,234	7,715
Total Sales Revenue	$230,266	$243,170

	Three Months Ended March 31,	
Gross Margin (in thousands)	2011	2010
Residential:		
Colorado	$6,120	$6,590
Nebraska	18,917	16,336
Iowa	16,281	15,455
Kansas	10,078	10,217
Total Residential	51,396	48,598
Commercial:		
Colorado	1,032	1,217
Nebraska	4,840	5,139
Iowa	4,163	4,613
Kansas	2,536	2,580
Total Commercial	12,571	13,549
Industrial:		
Colorado	36	23
Nebraska	50	163
Iowa	90	85
Kansas	231	183
Total Industrial	407	454
Transportation:		
Colorado	328	281
Nebraska	4,359	4,649
Iowa	1,325	1,200
Kansas	2,067	1,951
Total Transportation	8,079	8,081
Other:		
Colorado	31	27
Nebraska	608	612
Iowa	126	444
Kansas	311	263
Total Other	1,076	1,346
Total Regulated	73,529	72,028
Non-regulated Services	3,608	3,697
Total Gross Margin	$77,137	$75,725

	Three Months Ended March 31,	
Volumes Sold (in Dth)	2011	2010
Residential:		
Colorado	2,720,005	2,820,847
Nebraska	6,070,237	6,336,387
Iowa	5,313,290	5,393,894
Kansas	3,430,879	3,568,617
Total Residential	17,534,411	18,119,745
Commercial:		
Colorado	581,696	655,373
Nebraska	2,343,110	2,545,124
Iowa	2,845,746	2,908,104
Kansas	1,302,931	1,345,148
Total Commercial	7,073,483	7,453,749
Industrial:		
Colorado	15,614	3,754
Nebraska	13,248	219,970
Iowa	109,801	131,266
Kansas	196,328	110,624
Total Industrial	334,991	465,614
Transportation:		
Colorado	345,171	298,543
Nebraska	5,948,046	7,990,628
Iowa	5,553,065	5,312,748
Kansas	4,440,270	4,209,828
Total Transportation	16,286,552	17,811,747
Other:		
Colorado	—	—
Nebraska	—	976
Iowa	—	42,297
Kansas	44,985	59,009
Total Other	44,985	102,282
Total Volumes Sold	41,274,422	43,953,137

Degree Days	Three Months Ended March 31, 2011		
Heating Degree Days:	Actual	Variance From Normal	
Colorado	2,761	(4	)%
Nebraska	3,281	2	%
Iowa	3,694	—	%
Kansas*	2,625	2	%
Combined Gas Utilities Heating Degree Days	3,212	1	%

Degree Days	Three Months Ended March 31, 2010		
Heating Degree Days:	Actual	Variance From Normal	
Colorado	2,837	—	%
Nebraska	3,372	6	%
Iowa	3,525	(4	)%
Kansas*	2,691	6	%
Combined Gas Utilities Heating Degree Days	3,203	2	%

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

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' revenues and margins are expected in the fourth and first quarters of each year. Therefore, revenues for and certain expenses of, these operations fluctuate significantly among quarters. Depending upon the state jurisdiction, the winter heating season begins around November 1 and ends around March 31.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income was $19.3 million in the three months ended March 31, 2011 compared to Net income of $19.5 million for the three months ended March 31, 2010 as a result of:

Gross margin: Gross margin increased $1.4 million primarily due to approved rate cases, partially offset by 4% lower volumes.

Operations and maintenance: Operations and maintenance was comparable to the same period in the prior year.

Depreciation and amortization: Depreciation and amortization decreased $1.0 million primarily due to assets that became fully depreciated during 2010.

Interest expense, net: Interest expense, net increased $0.8 million primarily due to higher interest rates, partially offset by increased intercompany interest income.

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

Income tax benefit (expense): The effective tax rate for the three months ended March 31, 2011 was comparable to the same period in the prior year.

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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	Approved Capital Structure Debt
Nebraska Gas (1)	Gas	12/2009	3/2010	$12.1	$8.3	10.1 %	52.0 %	48.0 %
Iowa Gas (2)	Gas	6/2010	2/2011	$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 %
Colorado Electric (4)	Electric	1/2010	8/2010	$22.9	$17.9	10.5 %	52.0 %	48.0 %
Colorado Electric (5)	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. On August 18, 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 Public Advocate has filed several appeals which the NPSC has denied. The Public Advocate has filed a notice of appeal with the Court of Appeals.

(2) On June 8, 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 on February 10, 2011.

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

(4) 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 revenues. On August 5, 2010, the CPUC approved a settlement agreement for $17.9 million in annual revenues 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 operating income be shared with customers commencing August 6, 2010. The percentage of operating income 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. Colorado Electric filed a proposal for a sharing mechanism with the CPUC on April 27, 2011. Since August 2010, $1.0 million in off-system operating income has been deferred.

(5) 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 associated with the 180 MW generating facility 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.

Non-regulated Energy Group

An analysis of results from our Non-regulated Energy Group's operating segments follows (in thousands):

Oil and Gas

	Three Months Ended March 31, 2011	2010
Revenue	$17,906	$19,743
Operations and maintenance	10,567	9,734
Depreciation, depletion and amortization	7,321	6,111
Total operating expenses	17,888	15,845
Operating income (loss)	18	3,898
Interest expense, net	(1,383)	(782)
Other income (expense)	(185)	303
Income tax (expense) benefit	835	(1,071)
Net income (loss)	$(715)	$2,348

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

	Three Months Ended March 31, 2011	2010
Fuel production:		
Bbls of oil sold	103,550	84,391
Mcfe of natural gas sold	2,134,658	2,152,176
Mcf equivalent sales	2,755,958	2,658,522

	Three Months Ended March 31, 2011	2010
Average price received: (a)		
Gas/Mcf (b)	$4.65	$5.91
Oil/Bbl	$66.83	$74.39
Depletion expense/Mcfe	$2.36	$2.00

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids

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

	Three Months Ended March 31, 2011			
	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.25	$0.46	$0.55	$2.26
Piceance	0.68	0.80	0.25	1.73
Powder River [(a)]	1.31	—	1.29	2.60
Williston [(a)]	0.26	—	1.50	1.76
All other properties	1.66	—	0.40	2.06
Total average	$1.18	$0.28	$0.74	$2.20

(a) Powder River and Williston are primarily oil producing properties with relatively higher operating expenses on a per Mcfe basis.

	Three Months Ended March 31, 2010			
	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$1.40	$0.37	$0.72	$2.49
Piceance	0.53	0.81	0.38	1.72
Powder River [(a)]	1.37	—	1.13	2.50
Williston [(a)]	0.89	—	1.00	1.89
All other properties	1.22	—	0.13	1.35
Total average	$1.25	$0.25	$0.67	$2.17

(a) Powder River and Williston are primarily oil producing properties with relatively higher operating expenses on a per Mcfe basis.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net loss was $0.7 million for the three months ended March 31, 2011 compared to Net income of $2.3 million for the same period in 2010 as a result of:

Revenue: Revenue decreased $1.8 million primarily due to a 21% decrease in the average hedged price of natural gas and a 10% decrease in the average hedged price of crude oil, partially offset by a 23% increase in crude oil volumes primarily from new wells in our ongoing Bakken drilling program in North Dakota. The decrease in crude oil price was influenced by fixed price swaps previously entered into at prices significantly below current crude oil market prices. These swaps represent approximately 58% of our crude oil volume for the current quarter. Gas volumes, exclusive of gas liquids, decreased 1%.

Operations and maintenance: Operations and maintenance costs increased $0.8 million primarily due to increased compensation costs and ad valorem taxes.

Depreciation, depletion and amortization: Depreciation, depletion and amortization increased $1.2 million primarily due to a higher depletion rate and increased production. The increase in the depletion rate reflects the addition of higher cost crude oil reserves, primarily attributable to our Bakken drilling activities.

Interest expense, net: Interest expense, net increased $0.6 million primarily due to higher interest rates.

Other income (expense): Other income (expense) decreased $0.5 million primarily due to lower earnings from equity investments.

Income tax (expense) benefit: Income tax (expense) benefit for the first quarter of 2011 was impacted primarily by a $0.3 million credit for research and development projects.

Coal Mining

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Revenue	$15,495	$13,980
Operations and maintenance	14,572	10,241
Depreciation, depletion and amortization	4,618	2,890
Total operating expenses	19,190	13,131
Operating income (loss)	(3,695)	849
Interest income, net	960	318
Other income	569	556
Income tax benefit (expense)	868	(377)
Net income (loss)	$(1,298)	$1,346

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

	Three Months Ended March 31,	
	2011	2010
Tons of coal sold	1,370	1,392
Cubic yards of overburden moved	3,455	3,571

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net loss was $1.3 million for the three months ended March 31, 2011 compared to Net income of $1.3 million in the same period in 2010, as a result of:

Revenue: Revenue increased $1.5 million primarily due to a 10% increase in average price received per ton. The higher average sales price reflects the impact of price escalators in certain of our coal sales contracts. Approximately 35% of our coal production is sold under contracts where the sales price escalates based on actual mining cost increases. In addition, approximately 60% of our production is sold under contracts where the sales price may escalate with published indices, which may not necessarily represent changes in actual mining costs. The increase in price received per ton during the quarter was partially offset by a 2% decrease in tons sold. Sales volumes decreased in 2011 as new quantities sold to the Wygen III plant beginning in April 2010 were more than offset by the negative impact from plant outages and the suspension of operations at the Osage power plant.

Operations and maintenance: Operations and maintenance costs increased $4.3 million. Cost increases are reflective of the current phase of our mine where we have longer haul distances and higher overburden stripping costs. Additionally we experienced higher costs associated with drilling and blasting, equipment maintenance, fuel, and staffing levels for our train load-out facility. As noted above, approximately 60% of our production is sold under contracts which have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income, which is expected to continue to negatively impact 2011 results. Previous periods also included 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: Depreciation, depletion and amortization expense increased $1.7 million related to reclamation costs and increased depreciation on equipment.

Interest income, net: Interest income, net increased $0.6 million primarily due to increased lending to affiliates at higher interest rates.

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

Income tax benefit (expense): The tax benefit for the period ending March 31, 2011 was favorably impacted by research and development credits recorded. Tax expense recorded for the period ended March 31, 2010 was favorably impacted by the benefit generated by percentage depletion.

Energy Marketing

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Gross margin —		
Realized gross margin	$5,257	$12,053
Unrealized gross margin	(2,792)	(2,281)
Total gross margin	2,465	9,772
Operating expenses	5,757	5,426
Depreciation and amortization	139	132
Total operating expenses	5,896	5,558
Operating income (loss)	(3,431)	4,214
Interest expense, net	(452)	(762)
Other income (expense)	(1)	(31)
Income tax (expense) benefit	1,243	(1,228)
Net income (loss)	$(2,641)	$2,193

Gross margins by commodity:
Three Months Ended March 31,

	Gas	Oil	Coal[(a)]	Power[(b)]	Environmental[(b)]
2011					
Realized	$5,288	$258	$1,076	$(1,365)	$—
Unrealized	(3,477)	(1,981)	1,649	1,017	—
Total	$1,811	$(1,723)	$2,725	$(348)	$—
2010					
Realized	$10,521	$1,532	$—	$—	$—
Unrealized	(1,004)	(1,277)	—	—	—
Total	$9,517	$255	$—	$—	$—

(a) Coal marketing activity began June 1, 2010, the acquisition date of the coal marketing portfolio.
(b) Power and environmental marketing commenced operations late in third quarter of 2010.

Following is a summary of average daily quantities marketed:

	Three Months Ended March 31,	
	2011	2010
Natural gas physical sales — MMBtus	1,730,183	1,753,200
Crude oil physical sales — Bbls	21,243	13,430
Coal physical sales — Tons	36,532	—

Gas, oil and coal inventory held by Energy Marketing primarily consists of gas held in storage. Such gas is being held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date. Quantities held were as follows:

	As of March 31, 2011	As of December 31, 2010	As of March 31, 2010
Natural gas (MMBtus)	1,567,070	14,922,353	10,328,896
Crude oil (Bbls)	143,647	198,052	74,140
Coal (Tons)	40,095	1,529	—

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net loss was $2.6 million for the three months ended March 31, 2011 compared to Net income of $2.2 million in the same period in 2010 as a result of:

Gross margin: Gross margin decreased $7.3 million primarily driven by lower gross margin from both natural gas and crude oil marketing compared to the 2010 period. Power marketing activities, which began during the third quarter of 2010, produced a slight gross margin loss for the three months ended March 31, 2011. These decreases to gross margin were partially offset by approximately $2.7 million in gross margin provided by the coal marketing operations that began in the second quarter of 2010.

Operating expenses: Operating expenses increased $0.3 million primarily due to higher compensation expense related to staff marketing new commodities in new geographic regions, and an increase in fees primarily related to usage of letters of credit.

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

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

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

Income tax (expense) benefit: The effective income tax rate for the three months ended March 31, 2011 was comparable to the same period in the prior year.

Power Generation

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Revenue	$7,620	$8,068
Operations and maintenance	4,188	3,374
Depreciation and amortization	1,064	1,028
Total operating expenses	5,252	4,402
Operating income	2,368	3,666
Interest expense, net	(1,791)	(1,997)
Other (expense) income	1,204	(11)
Income tax expense	(595)	(578)

Net income	$1,186	$1,080

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

	Three Months Ended March 31, 2011		2010	
Contracted power plant fleet availability:				
Coal-fired plant	100.0	%	100.0	%
Natural gas-fired plant	100.0	%	100.0	%
Total availability	100.0	%	100.0	%

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income was $1.2 million for the three months ended March 31, 2011 compared to Net income of $1.1 million in the same period in 2010 as a result of:

Revenue: Revenue decreased primarily due to lower off-system sales.

Operations and maintenance: Operations and maintenance costs increased $0.8 million primarily due to increased corporate allocations associated with Colorado IPP and higher Wygen I operating costs.

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

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

Other (expense) income: Other (expense) income increased $1.2 million primarily due to higher earnings from our partnership investments and a gain on the sale of our ownership interest in the partnership which owned certain Idaho generation facilities.

Income tax expense: The effective tax rate for the three months ended March 31, 2011 was comparable to the same period in the prior year.

Corporate

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010. Net income was $0.9 million for the three months ended March 31, 2011 compared to Net loss of $5.0 million for the three months ended March 31, 2010 as a result of:

- An unrealized net, non-cash mark-to-market gain for the quarter ended March 31, 2011 of approximately $5.5 million on certain interest rate swaps compared to a $3.0 million unrealized net, non-cash mark-to-market loss on these interest rate swaps in the prior period.

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 three months ended March 31, 2011 and 2010 (in thousands)

Cash provided by (used in):	2011	2010
Operating activities	$111,271	$88,919
Investing activities	$(121,758)	$(78,050)
Financing activities	$22,065	$12,253

2011 Compared to 2010

Operating Activities

Net cash provided by operating activities was $22.4 million higher than in 2010 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $24.8 million higher than the prior year.

- Inflows from operating assets and liabilities were $14.8 million which is a decrease of $12.4 million from the prior year as a result of:

- Net outflows from working capital accounts were $29.2 million which is a decrease of $50.3 million from the prior year net inflows from working capital accounts. In addition to normal working capital changes, 2011 reflects increased cash inflows from higher withdrawals of gas storage inventories by Energy Marketing and Gas Utilities. Energy Marketing also experienced higher outflows in the current period related to higher margin posted on marketing transactions ; and

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

Investing Activities

Net cash used in investing activities was $43.7 million more than in 2010 reflecting higher capital additions. During 2011, cash outflows for property, plant and equipment additions totaled $122.5 million, including the partial 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 oil and gas property maintenance capital and development drilling.

Financing Activities

Net cash provided by financing activities was $9.8 million more than in 2010 primarily due to increased borrowings to finance our construction program. During 2011, we borrowed an additional $38.0 million on our Revolving Credit Facility, we retired $2.2 million of long-term debt, and we paid $14.4 million of cash dividends on common stock.

Dividends

Dividends paid on our common stock totaled $14.4 million for the three months ended March 31, 2011, or $0.365 per share. On April 26, 2011, our Board of Directors declared an additional quarterly dividend of $0.365 per share payable June 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 March 31, 2011, we had approximately $44 million of cash unrestricted for operations.

Revolving Credit Facility

Our $500 million Revolving Credit Facility 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 are 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.

Our consolidated net worth was $1.1 billion at March 31, 2011, which was approximately $240 million in excess of the net worth we are required to maintain under the credit facility. At March 31, 2011, our long-term debt ratio was 51.6%, our total debt leverage ratio (long-term debt and short-term debt) was 57.0%, and our recourse leverage ratio was approximately 57.8%.
At March 31, 2011, we had borrowings of $187 million and letters of credit outstanding of $51 million on our Revolving Credit Facility. Available capacity remaining on our Revolving Credit Facility was approximately $262 million at March 31, 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.

In addition to covenant violations, an event of default under the 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 $35.0 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 principal and interest outstanding and the cash collateralization of outstanding letter of credit obligations.

Enserco Credit Facility

Enserco has a two-year, $250 million committed credit facility expiring in May 2012. The facility includes a $100 million accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility. Maximum borrowings under the facility are subject to a sublimit 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%. Our covenants include tangible net worth, net working capital and realized net working capital requirements and, as of March 31, 2011, Enserco was in compliance with these covenants.

At March 31, 2011, $147 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

Corporate Term Loan

In December 2010, we entered into a one-year $100 million term loan (the "Loan") with J.P. Morgan and Union Bank due in December 2011. The cost of borrowing under the Loan was based on a spread of 137.5 basis points over LIBOR (1.69% at March 31, 2011). The covenants are substantially the same as those included in the Revolving Credit Facility and we were in compliance as of March 31, 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 shareholders is derived from these cash flows. As a result of certain statutory or regulatory limitations or financing agreements, our subsidiaries could have restrictions on the amount of distributions they can make to us.

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 March 31, 2011, the restricted net assets at our Electric and Gas Utilities were approximately $194 million compared to $197 million at December 31, 2010.

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 March 31, 2011 were $86 million compared to $93 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 and long-term financings. We intend to settle the equity forward in the fourth quarter of 2011. We may complete an additional long-term senior unsecured debt financing at the holding company level in 2011. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, during the construction period of our new generation facilities in Colorado, we may exceed this level on a temporary basis.

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").

Based on the closing Black Hills Corporation common stock price of $33.44 on March 31, 2011, and the forward price on that date for the equity forward of $27.95 and over-allotment shares of $27.95, the fair value net cash settlement of the 4,000,000 equity forward instrument and 413,519 over-allotment shares was approximately $24 million. The Forward Agreements require a 60 day notice prior to settlement for cash or net share settlements. Forward prices and volume-weighted average market prices for the period between when notice is provided and settlement are used to calculate cash and net share settlement amounts.

At March 31, 2011, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares to J.P. Morgan in exchange for cash of $123 million. Assuming required notices were given and actions taken, the forward instruments could have also been net settled at March 31, 2011 with delivery of cash of approximately $24 million or approximately 706,000 shares of common stock to J.P. Morgan. We may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settle at any date up to maturity, for all or a portion of the equity forward shares. It is our intent to settle the equity forward with the physical delivery of shares in the fourth quarter of 2011.

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 months ended March 31, 2011 and 2010 we recorded a $5 million pre-tax unrealized mark-to-market non-cash gain and $3 million pre-tax unrealized mark-to-market non-cash loss on the swaps, respectively. The mark-to-market value on these swaps was a liability of $49 million at March 31, 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 $0.3 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 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 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 value on the termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps, having a maximum remaining term of 5.75 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 $20 million at March 31, 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 Activities

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 stand-alone 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 counterparty 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 is not expected to result in a significant increase to the liquidity requirements of the marketing business 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 March 31, 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 March 31, 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 Three Months Ended March 31, 2011	Total 2011 Planned Expenditures
Utilities:		
Electric Utilities (1)(2)	$45,396	$222,500
Gas Utilities	6,141	65,200
Non-regulated Energy:		
Oil and Gas (3)	7,444	60,900
Power Generation (4)	40,606	91,700
Coal Mining	3,196	12,500
Energy Marketing	1,182	2,400
Corporate	2,119	7,000
Total	$106,084	$462,200

(1) The 2011 total planned expenditures include capital requirements associated with our plans to build a 180 MW gas-fired power generation facility to serve our Colorado Electric customers. We spent $35.8 million during the first three months of 2011. The total construction cost of the facility is expected to be approximately $227 million and construction is expected to be completed by the end of 2011. The planned expenditures indicated for 2011 include optimizing accelerated depreciation for federal income tax purposes in the form of bonus depreciation, which was retroactively reinstated by Congress and signed into law by the President of the United States in September 2010.

(2) 2011 planned expenditures include expected spending for planned wind projects for both Black Hills Power and Colorado Electric. Combined 2012 planned expenditures on these projects are expected to be approximately $56.2 million and 2013 planned expenditures are expected to be approximately $9.6 million.

(3) Oil and Gas planned expenditures have increased $12.0 million from our prior forecast disclosed in our Form 10-K, primarily due to development in the Bakken formation and our Mancos test program.

(4) 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 $40.5 million during the first three 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 increased $5.9 million from $83.5 million at December 31, 2010 to $89.4 million at March 31, 2011. Approximately $56.1 million of the firm transportation and storage fee obligations relate to the 2011-2013 period with the remaining 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 approximately $260 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. As of March 31, 2011, committed contracts for equipment purchases and for construction were 100% and 89% complete, respectively, for the Colorado Electric utility and 100% and 77% complete, respectively, for the Power Generation segment.

Guarantees

Except as noted below, there have been no new 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.

New Accounting Pronouncements

Other than the new 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, and 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 continually evaluate financing options including senior notes, first mortgage bonds, term loans and project financing. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our ability to access 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 power generation 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.

- 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 to supply our Colorado Electric subsidiary through a combination of long-term debt and issuance of equity.

- We expect contributions to our defined benefit pension plans to be approximately $0.6 million and $13.4 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' ability to generate sufficient stable cash flow over an extended period of time.

- We expect to make approximately $462.2 million of capital expenditures in 2011. 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 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 crude oil and gas operations.

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

- 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.

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

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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 derivative contracts are summarized below (in thousands):

	As of March 31, 2011		As of December 31, 2010		As of March 31, 2010	
Net derivative (liabilities) assets	$(2,455	)	$(7,188	)	(6,475	)
Cash collateral	3,720		10,355		8,094	
	$1,265		$3,167		1,619	

Non Regulated Trading Activities

The following table provides a reconciliation of Energy Marketing 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 three months ended March 31, 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	(6,585	)
Unrealized gain (loss) on new positions entered during the period and still existing at March 31, 2011	15,530	
Realized (gain) loss on positions that existed at December 31, 2010 and were settled during the period	2,083	
Change in cash collateral	(974	)
Unrealized gain (loss) on positions that existed at December 31, 2010 and still exist at March 31, 2011	(18,654	)
Total fair value of energy marketing positions at March 31, 2011	$14,818	(a)

(a) The fair value of energy marketing positions consists of derivative assets/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):

	As of March 31, 2011	As of December 31, 2010	As of September 30, 2010	As of June 30, 2010	As of March 31, 2010
Net derivative assets	$11,518	$28,524	$51,734	$31,720	$25,634
Cash collateral	2,984	3,958	(7,365)	—	171
Market adjustment recorded in material, supplies and fuel	316	(9,064)	(18,716)	(8,469)	(11,039)
Total fair value of energy marketing positions marked-to-market	$14,818	$23,418	$25,653	$23,251	$14,766

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 Less than 1 year	1 - 2 years	Total Fair Value
Cash collateral	$2,984	$—	$2,984
Level 1	—	—	—
Level 2	5,790	1,423	7,213
Level 3	1,664	2,641	4,305
Market value adjustment for inventory (see footnote (a) above)	316	—	316
Total fair value of our energy marketing positions	$10,754	$4,064	$14,818

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 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 energy 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 March 31, 2011 energy 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 energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$14,818	
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	(27,530	)
Fair value of all forward positions (non-GAAP)	(12,712	)
Cash collateral included in GAAP marked-to-market fair value	(2,984	)
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$(15,696	)

* We consider this measure 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 are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	6/2/2009	Swap	04/11 - 06/11	5,000	$5.99
AECO	6/2/2009	Swap	04/11 - 06/11	800	$5.89
NWR	6/2/2009	Swap	04/11 - 06/11	1,500	$5.54
San Juan El Paso	6/25/2009	Swap	04/11 - 06/11	2,500	$5.55
CIG	6/25/2009	Swap	04/11 - 06/11	1,750	$5.33
CIG	9/2/2009	Swap	07/11 - 09/11	500	$5.32
NWR	9/2/2009	Swap	07/11 - 09/11	500	$5.32
San Juan El Paso	9/2/2009	Swap	07/11 - 09/11	2,500	$5.54
CIG	9/25/2009	Swap	07/11 - 09/11	500	$5.59
NWR	9/25/2009	Swap	07/11 - 09/11	1,000	$5.59
AECO	9/25/2009	Swap	07/11 - 09/11	500	$5.76
San Juan El Paso	9/25/2009	Swap	07/11 - 09/11	5,000	$5.91
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	07/11 - 09/11	500	$5.19
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

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	4/8/2009	Swap	04/11 - 06/11	5,000	$68.80
NYMEX	4/23/2009	Swap	04/11 - 06/11	5,000	$65.10
NYMEX	6/2/2009	Swap	04/11 - 06/11	5,000	$75.86
NYMEX	6/4/2009	Put	04/11 - 06/11	5,000	$67.00
NYMEX	9/2/2009	Swap	07/11 - 09/11	5,000	$75.10
NYMEX	9/2/2009	Put	07/11 - 09/11	5,000	$63.00
NYMEX	9/29/2009	Swap	07/11 - 09/11	5,000	$74.00
NYMEX	10/6/2009	Put	07/11 - 09/11	5,000	$65.00
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	04/11 - 06/11	1,000	$85.35
NYMEX	11/19/2009	Swap	07/11 - 09/11	1,500	$85.95
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

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 March 31, 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 March 31, 2011 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 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

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.

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
January 1, 2011 - January 31, 2011	9,402	$30.19	—	—
February 1, 2011 - February 28, 2011	12,489	$31.75	—	—
March 1, 2011 - March 31, 2011	—	$—	—	—
Total	21,891	$31.08	—	—

(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.

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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 dialog 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 our Wyodak Coal Mine, are subject to regulation by MSHA under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present certain mining safety and health matters, for the three-month period ended March 31, 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 March 31, 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 March 31, 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 March 31, 2011 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for our mining complex. All citations were abated within 24 hours of issue.

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 (in dollars)	Number of Legal Actions Pending Before the Federal Mining Safety and Health Review Commission
1	—	—	—	$512	—

ITEM 6.	Exhibits	Description
	Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
	Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
	Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
	Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
	Exhibit 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: May 10, 2011

EXHIBIT INDEX

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