BLACK HILLS CORP /SD/
Form 10-Q
May 07, 2010

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, 2010.

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 o   No o

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

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

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

Yes o No x

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

Class	Outstanding at April 30, 2010
Common stock, $1.00 par value	39,175,311 shares

TABLE OF CONTENTS

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:

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for the Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of Aquila's regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa
ASC	Accounting Standards Codification
ASC 810-10-15	ASC 810-10-15, "Consolidation of Variable Interest Entities"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASC 932-10-S99	ASC 932-10-S99, "Extractive Activities – Oil and Gas, SEC Materials"
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
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, including the gas and electric utility properties acquired from Aquila
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 formed to acquire and own the utility properties acquired from Aquila, all which are now doing business as Black Hills Energy
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company

Colorado Electric	Black Hills Colorado Electric Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings

Corporate Credit Facility	Our $525 million credit facility which was terminated on April 15, 2010
CPUC	Colorado Public Utilities Commission
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
GAAP	Generally Accepted Accounting Principles
GSRS	Gas Safety and Reliability Surcharge
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 Production
IPP Transaction	Our July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings Fund Management Ltd and IIF BH Investment LLC
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
KCC	Kansas Corporation Commission
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
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
NPA	Nebraska Public Advocate
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
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
SEC Release No. 33-8995	SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting"
WPSC	Wyoming Public Service Commission

WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

4

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended March 31,	
	2010	2009
	(in thousands, except per share amounts)	
Operating revenues	$442,332	$437,943
Operating expenses:		
Fuel and purchased power	252,535	261,020
Operations and maintenance	42,622	39,335
Gain on sale of assets	(2,683)	(25,971)
Administrative and general	39,088	41,766
Depreciation, depletion and amortization	28,395	33,325
Taxes, other than income taxes	12,673	11,698
Impairment of long-lived assets	-	43,301
Total operating expenses	372,630	404,474
Operating income	69,702	33,469
Other income (expense):		
Interest expense	(21,766)	(18,901)
Interest rate swap - unrealized (loss) gain	(3,035)	14,763
Interest income	246	528
Allowance for funds used during construction - equity	2,028	1,372
Other income, net	418	744
Total other expenses	(22,109)	(1,494)
Income from continuing operations before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	47,593	31,975
Equity in earnings (loss) of unconsolidated subsidiaries	317	(327)
Income tax expense	(16,476)	(6,023)
Income from continuing operations	31,434	25,625
Income from discontinued operations, net of taxes	-	766
Net income	$31,434	$26,391
Weighted average common shares outstanding:		
Basic	38,848	38,511
Diluted	39,009	38,563
Earnings per share:		
Basic-		
Continuing operations	$0.81	$0.67
Discontinued operations	-	0.02

Total earnings per share - basic	$0.81	$0.69
Diluted-		
Continuing operations	$0.81	$0.66
Discontinued operations	-	0.02
Total earnings per share - diluted	$0.81	$0.68
Dividends declared per share of common stock	$0.36	$0.355

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, 2010	December 31, 2009	March 31, 2009
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$136,023	$112,901	$121,562
Restricted cash	27,215	17,502	-
Accounts Receivables, net	242,189	274,489	233,921
Materials, supplies and fuel	91,111	123,322	59,139
Derivative assets, current	54,773	37,747	79,443
Income tax receivable, net	-	2,031	-
Deferred income tax asset, current	5,610	4,523	11,788
Regulatory assets, current	42,876	25,085	19,053
Other current assets	26,189	27,270	11,517
Total current assets	625,986	624,870	536,423
Investments	18,466	18,524	19,956
Property, plant and equipment	3,045,126	2,975,993	2,750,760
Less accumulated depreciation and depletion	(830,423)	(815,263)	(750,748)
Total property, plant and equipment, net	2,214,703	2,160,730	2,000,012
Other assets:			
Goodwill	353,734	353,734	359,093
Intangible assets, net	4,248	4,309	4,870
Derivative assets, non-current	5,877	3,777	11,606
Regulatory assets, non-current	117,561	135,578	137,108
Other assets, non-current	18,064	16,176	12,041
Total other assets	499,484	513,574	524,718
TOTAL ASSETS	$3,358,639	$3,317,698	$3,081,109
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$194,342	$229,352	$191,817
Accrued liabilities	140,939	151,504	129,405
Derivative liabilities, current	68,834	57,166	105,883
Accrued income taxes, net	10,568	-	19,794
Regulatory liabilities, current	9,850	7,092	14,939
Notes payable	223,000	164,500	479,800
Current maturities of long-term debt	24,426	35,245	32,082
Total current liabilities	671,959	644,859	973,720
Long-term debt, net of current maturities	993,514	1,015,912	471,226
Deferred credits and other liabilities:			

Deferred income tax liability, non-current	270,079	262,034	222,157
Derivative liabilities, non-current	12,081	11,999	20,656
Regulatory liabilities, non-current	44,788	42,458	39,514
Benefit plan liabilities	144,199	140,671	160,397
Other deferred credits and other liabilities	114,021	114,928	121,842
Total deferred credits and other liabilities	585,168	572,090	564,566
Stockholders' equity:			
Common stockholders' equity -			
Common stock $1 par value; 100,000,000 shares authorized; Issued 39,178,067; 38,977,526 and 38,796,005 shares, respectively	39,178	38,978	38,796
Additional paid-in capital	593,589	591,390	585,244
Retained earnings	491,202	473,857	460,091
Treasury stock at cost – 4,284; 8,834 and 4,725 shares, respectively	(112)	(224)	(119)
Accumulated other comprehensive loss	(15,859)	(19,164)	(12,415)
Total stockholders' equity	1,107,998	1,084,837	1,071,597
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,358,639	$3,317,698	$3,081,109

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, 2010	2009
	(in thousands)	
Operating activities:		
Net income	$31,434	$26,391
Income from discontinued operations, net of taxes	-	(766)
Income from continuing operations	31,434	25,625
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	28,395	33,325
Impairment of long-lived assets	-	43,301
Derivative fair value adjustments	(1,579)	6,154
Gain on sale of operating assets	(2,683)	(25,971)
Stock compensation	989	18
Unrealized mark-to-market loss (gain) on interest rate swaps	3,035	(14,763)
Deferred income taxes	3,492	(5,427)
Equity in (earnings) loss of unconsolidated subsidiaries	(317)	327
Allowance for funds used during construction - equity	(2,028)	(1,372)
Employee benefit plans	3,940	4,420
Other non-cash adjustments	2,382	2,241
Change in operating assets and liabilities:		
Materials, supplies and fuel	21,755	65,838
Accounts receivable and other current assets	24,044	123,993
Accounts payable and other current liabilities	(24,716)	(83,994)
Regulatory assets	3,277	23,477
Regulatory liabilities	2,834	9,550
Other operating activities	(5,335)	(7,290)
Net cash provided by operating activities of continuing operations	88,919	199,452
Net cash provided by operating activities of discontinued operations	-	883
Net cash provided by operating activities	88,919	200,335
Investing activities:		
Property, plant and equipment additions	(81,290)	(71,272)
Proceeds from sale of ownership interest in operating assets	6,105	51,878
Working capital adjustment of purchase price allocation on Aquila assets	-	7,900
Other investing activities	(2,865)	135
Net cash used in investing activities	(78,050)	(11,359)
Financing activities:		
Dividends paid	(14,089)	(13,753)
Common stock issued	1,522	764
Increase in short-term borrowings	108,500	33,000
Decrease in short-term borrowings	(50,000)	(257,000)
Long-term debt - repayments	(33,217)	(22)

Other financing activities	(463)	1,065
Net cash provided by (used in) financing activities	12,253	(235,946)
Increase (decrease) in cash and cash equivalents	23,122	(46,970)
Cash and cash equivalents:		
Beginning of period	112,901	168,532
End of period	$136,023	$121,562

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 2009 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 2009 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 which are, in the opinion of management, necessary for a fair presentation of the March 31, 2010, December 31, 2009 and March 31, 2009 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, 2010, and our financial condition as of March 31, 2010 and December 31, 2009, 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. These reclassifications had no effect on total assets, net income, cash flows or earnings per share.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Extractive Activities - Oil and Gas Reserves (SEC Release #33-8995), ASC 932-10-S99

The FASB issued an accounting standards update which aligns the oil and gas reserve estimation and disclosure requirements with the SEC released Final Rule, "Modernization of Oil and Gas Reporting" amending the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technology advances. Key revisions include the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the oil and gas prices used to determine reserves from the period-end price to a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months before the end of the reporting period. The amendment was effective for reporting periods ending on or after December 31, 2009. The implementation of this SEC requirement resulted in additional depletion expense of $1.3 million in the fourth quarter of 2009.

Consolidation of Variable Interest Entities, ASC 810-10-15

In June 2009, the FASB issued a revision regarding consolidations. The amendment requires a company to consider whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It requires additional disclosures about the involvement with variable interest entities and any significant changes in risk exposure due to that involvement. This standard is effective for annual periods that begin after November 15, 2009 with re-evaluation annually. The adoption of this standard in January 2010 currently did not have any impact on our consolidated financial statements, results of operations, and cash flows. We also evaluated this standard on a segment basis and the adoption of this standard did not have any impact on our segment reporting.

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 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 are effective on January 1, 2011. The guidance requires additional disclosures, but did not impact our financial position, results of operations or cash flows.

Recently Issued Accounting Standards and Legislation

Patient Protection and Affordable Care Act (HR 3590)

On March 23, 2010, the President of the United States signed into law comprehensive healthcare reform legislation under the Patient Protection and Affordable Care Act, as amended by the Healthcare and Education Reconciliation Act. Included among the provisions of the law is a change in the tax treatment of the Medicare Part D subsidy (the "subsidy") which would affect 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 adjustment to our regulated utilities was recorded in regulatory assets. The impact to our earnings with respect to our non-regulated entities was approximately $0.1 million.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended	
	March 31, 2010	March 31, 2009
	(in thousands)	
Non-cash investing activities-		
Property, plant and equipment acquired with accrued liabilities	$23,473	$28,947
Cash (paid) refunded during the period for-		
Interest (net of amounts capitalized)	$(10,182)	$(10,177)
Income taxes	$44	$24,495

March 2009 includes less than $0.1 million of cash for discontinued operations.

9

(4) MATERIALS, SUPPLIES AND FUEL

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

Major Classification	March 31, 2010	December 31, 2009	March 31, 2009
Materials and supplies	$ 32,200	$ 31,535	$ 34,574
Fuel - Electric Utilities	9,028	7,128	7,270
Natural gas in storage - Gas Utilities	4,868	24,053	7,590
Gas and oil held by Energy Marketing*	45,015	60,606	9,705
Total materials, supplies and fuel	$ 91,111	$ 123,322	$ 59,139

* As of March 31, 2010, December 31, 2009 and March 31, 2009, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(11.0) million, $(0.3) million and $(2.4) million, respectively (see Note 13 for further discussion of Energy Marketing trading activities).

Gas and oil 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 in the future. Natural gas volumes held as of March 31, 2010, December 31, 2009 and March 31, 2009 include 10.3 Bcf, 12.2 Bcf, and 2.7 Bcf. Crude oil volumes held as of March 31, 2010, December 31, 2009 and March 31, 2009 include 74,000 Bbl, 69,000 Bbl, and 41,000 Bbl, respectively.

Natural gas in storage at our Gas Utilities represents primarily gas purchased for use by our customers. The natural gas in storage fluctuates with the seasonality of our business and the commodity price of natural gas. Volumes held in storage by us vary due to the season and carrying values are impacted by price fluctuations. Volumes held as of March 31, 2010, December 31, 2009 and March 31, 2009 include 1,236,050 MMBtu, 6,866,550 MMBtu and 907,900 MMBtu, respectively.

(5) ALLOWANCE FOR DOUBTFUL ACCOUNTS

Our Accounts receivable represents primarily customer trade accounts at our Electric Utilities and Gas Utilities and counterparty trade accounts at our Energy Marketing segment. This balance fluctuates due to the seasonality of our regulated 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 receivables. We regularly review our trade receivables allowance by considering such factors as historical experience, credit-worthiness, the age of the receivable balances and current economic conditions that may affect the ability to pay.

Following is a summary of receivables (in thousands):

	March 31, 2010	December 31, 2009	March 31, 2009
Accounts receivable	$ 214,028	$ 217,723	$ 199,633
Unbilled revenues	33,392	61,387	42,120

Total accounts receivable		247,420			279,110			241,753	
Less allowance for doubtful accounts		(5,231	)		(4,621	)		(7,832	)
Net accounts receivable	$	242,189		$	274,489		$	233,921	

(6) NOTES PAYABLE

Our credit facilities and debt securities contain certain restrictive financial covenants including, among others, interest expense coverage ratios, recourse leverage ratios and consolidated net worth ratios. At March 31, 2010, we were in compliance with these financial covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

Acquisition Facility

In conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under the Acquisition Facility, which is recorded in Notes payable on the accompanying Condensed Consolidated Balance Sheets as of March 31, 2009. In May 2009, we repaid the Acquisition Facility with proceeds of $30.2 million for the sale of 25% of the Wygen III plant to MDU, net proceeds from the $250 million public debt offering, and a borrowing of $104.6 million on our Corporate Credit Facility.

Corporate Credit Facility

Our consolidated net worth was $1,108.0 million at March 31, 2010, which was approximately $283.1 million in excess of the net worth we are required to maintain under the Corporate Credit Facility. At March 31, 2010, our long-term debt ratio was 47.3%, our total debt coverage leverage ratio (long-term debt and short-term debt) was 52.8%, and our recourse leverage ratio was 54.7%. Our interest expense coverage ratio for the twelve month period ended March 31, 2010 was 3.7 to 1.0. We were in compliance with our covenants as of March 31, 2010.

Enserco Credit Facility

In May 2009, Enserco entered into an agreement for a $300 million committed credit facility. This credit facility expired on May 7, 2010 and was a borrowing base line of credit, which allowed for the issuance of letters of credit and for borrowings. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds (see Note 20).

At March 31, 2010, $101.8 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding. Amortization of deferred financing costs under our committed Enserco Credit Facility is included in interest expense and for the three months ended March 31, 2010 was approximately $0.5 million. Amortization of deferred financing costs for the three months ended March 31, 2009 under our previous uncommitted Enserco Credit Facility was $0.2 million.

(7) LONG-TERM DEBT

Black Hills Power Series AC Bonds

In February 2010, the Black Hills Power Series AC bonds matured. These were paid in full for $30.0 million plus accrued interest of $1.2 million.

Black Hills Power Series Y Bonds

In February 2010, Black Hills Power provided notice to the bondholders of its intent to call the Series Y bonds in full. These bonds were originally due in 2018. A total of $2.7 million was paid on March 31, 2010, which includes the balance of $2.5 million plus accrued interest and an early redemption premium of 2.6%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Condensed Consolidated Balance Sheets and will be amortized over the remaining term of the original bonds.

Black Hills Power Series Z Bonds

In April 2010, Black Hills Power provided notice to the bondholders of its intent to call the Series Z bonds in full. These bonds were originally due to mature in 2021. The principal amount due on the bonds has been reclassified to Current maturities of long-term debt on the accompanying Condensed Consolidated Balance Sheets. A payment of $19.2 million for principal of $18.3 million, accrued interest and an early redemption premium of 4.675% will be made on May 31, 2010. The early redemption premium will be recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Condensed Consolidated Balance Sheets and will be amortized over the remaining term of the original bonds.

(8) EARNINGS PER SHARE

Basic earnings per share from continuing operations is computed by dividing income from continuing operations by the weighted-average number of common shares outstanding during the period. Diluted earnings per share from continuing operations are computed by using all dilutive common shares potentially outstanding during a period. A reconciliation of Income from continuing operations and basic and diluted share amounts is as follows (in thousands):

Period ended March 31, 2010	Three Months	
	Income	Average Shares
Income from continuing operations	$31,434	
Basic earnings	$31,434	38,848
Dilutive effect of:		
Restricted stock	-	89
Other	-	72
Diluted earnings	$31,434	39,009

Period ended March 31, 2009	Three Months	
	Income	Average Shares
Income from continuing operations	$25,625	
Basic earnings	$25,625	38,511
Dilutive effect of:		
Restricted stock	-	52
Diluted earnings	$25,625	38,563

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,	
	2010	2009
Options to purchase common stock	264	435

(9) OTHER COMPREHENSIVE INCOME

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Net income	$31,434	$26,391
Other comprehensive income, net of tax:		
Minimum pension liability adjustments (net of tax of $(7))	12	-
Fair value adjustments on derivatives designated as cash flow hedges (net of tax of $(591) and $(1,144), respectively)	1,416	2,998
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(1,061) and $(1,917), respectively)	1,877	3,370
Comprehensive income	$34,739	$32,759

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

	March 31, 2010	December 31, 2009	March 31, 2009
Derivatives designated as cash flow hedges	$(6,182)	$(9,462)	$1,818
Employee benefit plans	(9,624)	(9,636)	(14,127)
Amount from equity-method investees	(53)	(66)	(106)
Total	$(15,859)	$(19,164)	$(12,415)

(10) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the first three months of 2010, as reported in Note 11 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

Equity Compensation Plans

- We granted 77,693 target performance shares to certain officers and business unit leaders for the January 1, 2010 through December 31, 2012 performance period. Actual shares are not issued until the end of the performance plan period (December 31, 2012). 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, the ending stock price must be at least equal to 75% of the beginning stock price 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 $24.25 per share.

- We issued 9,625 shares of common stock under the 2009 short-term incentive compensation plan during the three months ended March 31, 2010. Pre-tax compensation cost related to the awards was approximately $0.3 million, which was accrued for in 2009.

- We granted 149,028 restricted common shares during the three months ended March 31, 2010. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $3.9 million will be recognized over the three-year vesting period.

- 30,000 stock options were exercised during the three months ended March 31, 2010 at a weighted-average exercise price of $21.875 per share which provided $0.7 million of proceeds.

Total compensation expense recognized for all equity compensation plans for the three months ended March 31, 2010 and 2009 was $1.8 million and $0.4 million, respectively.

As of March 31, 2010, total unrecognized compensation expense related to non-vested stock awards was $10.1 million and is expected to be recognized over a weighted-average period of 2.3 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan 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 31,071 new shares at a weighted-average price of $27.80 during the three months ended March 31, 2010. At March 31, 2010, 264,911 shares of unissued common stock were available for future offering under the Plan.

Dividend Restrictions

Our Corporate 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: interest expense coverage ratio of not less than 2.5 to 1.0; 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 since January 1, 2005. As of March 31, 2010, 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 at March 31, 2010:

- 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, 2010, the restricted net assets at our Electric and Gas Utilities were approximately $214.5 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, we may be restricted from making dividends from Enserco to the parent company of Enserco. The restricted net assets at March 31, 2010 at Enserco were $113.5 million.

(11) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Plans"). One Plan covers employees of the following subsidiaries who meet certain eligibility requirements: Black Hills Service Company, Black Hills Power, WRDC and BHEP. The second Plan covers employees of our subsidiary, Cheyenne Light, who meet certain eligibility requirements. The third Plan covers employees of the Black Hills Energy utilities who meet certain eligibility requirements.

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Service cost	$1,533	$1,929
Interest cost	3,773	3,679
Expected return on plan assets	(3,623)	(3,458)
Prior service cost	305	41
Net loss	500	752
Net periodic benefit cost	$2,488	$2,943

We made no contributions to the Plans in the first quarter of 2010. Contributions of $0.01 million and $32.5 million are anticipated to be made to the Plans for 2010 and 2011, respectively.

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 are as follows (in thousands):

	Three Months Ended March 31,	
	2010	2009
Service cost	$377	$260
Interest cost	611	542
Expected return on plan assets	(52)	(56)
Prior service cost	(77)	(22)
Net transition obligation	-	15
Net (gain) loss	159	(8)
Net periodic benefit cost	$1,018	$731

We anticipate that we will make aggregate contributions to the Healthcare Plans for the 2010 and 2011 fiscal years of approximately $3.8 million and $4.0 million, respectively. The contributions are expected to be made in the form of benefits payments.

It has been determined that our post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The decrease in net periodic postretirement benefit cost due to the subsidy was approximately $0.1 million for the three month period ended March 31, 2010.

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 are as follows (in thousands):

	Three Months Ended March 31,	
	2010	2009
Service cost	$171	$117
Interest cost	321	344
Prior service cost	1	1
Net loss	71	147
Net periodic benefit cost	$564	$609

We anticipate that we will make aggregate contributions to the Supplemental Plans for the 2010 fiscal year of approximately $0.9 million. The contributions are expected to be made in the form of benefit payments.

(12) 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, 2010, substantially all of our operations and assets are located within the United States.

We conduct our operations through the following six reportable segments:

Utilities Group -

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

- Gas Utilities, which supplies natural gas utility service 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 and Idaho. 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 to be constructed in Colorado which are expected to be placed into service by December 31, 2011;

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

- Energy Marketing, which markets natural gas, crude oil and related services primarily in the United States and Canada.

Segment information follows the same accounting policies as described in Note 1 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K. In accordance with accounting standards for regulated operations, intercompany fuel and energy sales to the regulated utilities are not eliminated.

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

Three Months Ended March 31, 2010	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$148,636	$ 173	$9,852
Gas Utilities(a)	243,170	-	19,498
Non-regulated Energy:			
Oil and Gas	19,743	-	2,348
Power Generation	8,068	-	1,080
Coal Mining	6,882	7,098	1,346
Energy Marketing	9,772	-	2,193
Corporate(b)	-	-	(4,967)
Inter-segment eliminations	-	(1,210)	84
Total	$436,271	$ 6,061	$31,434

Three Months Ended March 31, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$137,060	$ 215	$9,317
Gas Utilities	256,337	-	17,265
Non-regulated Energy:			
Oil and Gas(c)	16,511	-	(25,720)
Power Generation(d)	7,619	-	17,153
Coal Mining	7,937	6,465	819
Energy Marketing	6,820	-	1,037
Corporate(b)	-	-	5,536
Inter-segment eliminations	-	(1,021)	218
Total	$432,284	$ 5,659	$25,625

(a) Income (loss) from continuing operations includes $1.7 million after-tax gain on sale of operating assets at Nebraska Gas.

(b) Income (loss) from continuing operations includes a $2.0 million net after-tax mark-to-market loss on interest rate swaps for the three months ended March 31, 2010 and a $9.6 million net after-tax mark-to-market gain on interest rate swaps for the three months ended March 31, 2009.

(c) As a result of lower natural gas prices at March 31, 2009, our Income (loss) from continuing operations reflects a $27.8 million after-tax non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment in the first quarter of 2009 (see Note 18).

(d)

Income (loss) from continuing operations includes $16.9 million after-tax gain on sale to MEAN of 23.5% ownership interest in Wygen I power generation facility.

	March 31, 2010	December 31, 2009	March 31, 2009
Total assets			
Utilities:			
Electric Utilities	$1,701,329	$1,659,375	$1,522,885
Gas Utilities	644,734	684,375	653,860
Non-regulated Energy:			
Oil and Gas	348,156	338,470	357,233
Power Generation	185,856	161,856	121,489
Coal Mining	82,776	76,209	75,092
Energy Marketing	324,478	321,207	262,441
Corporate	71,310	76,206	88,109
Total	$3,358,639	$3,317,698	$3,081,109

(13) 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 and natural gas reserves and production, and fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated Gas Utilities segment resulting 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 natural gas marketing transacted in Canadian dollars.

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

We actively manage our exposure to certain market risks as described in Note 3 of the Notes to our Consolidated Financial Statements in our 2009 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 14.

Trading Activities

Natural Gas and Crude Oil Marketing

We have a natural gas and crude oil marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the western and central regions of the United States and Canada.

Contracts and other activities at our natural gas and crude oil marketing operations are accounted for under the accounting standards for energy trading contracts. As such, all of the contracts and other activities at our natural gas and crude oil 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 natural gas and crude oil 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 and crude oil 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 gas marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee. Our contracts do not include credit risk-related contingent features.

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas and oil 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 natural gas and crude oil marketing activities and derivative commodity instruments are as follows:

	Outstanding at March 31, 2010		Outstanding at December 31, 2009		Outstanding at March 31, 2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	240,400	19	231,703	22	273,496	31
Natural gas basis swaps sold	245,790	19	232,673	22	280,478	31
Natural gas fixed-for-float swaps purchased	87,161	20	60,927	16	101,094	21
Natural gas fixed-for-float swaps sold	99,233	22	72,904	25	107,705	21
Natural gas physical purchases	125,570	24	120,680	27	143,642	19
Natural gas physical sales	123,620	24	124,830	27	136,504	19

	Outstanding at March 31, 2010		Outstanding at December 31, 2009		Outstanding at March 31, 2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	5,296	9	5,048	12	5,070	9
Crude oil physical sales	5,647	9	4,998	12	4,301	9
Crude oil swaps/options purchased	-	-	-	-	67	1
Crude oil swaps/options sold	94	2	69	2	119	4

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on March 31, 2010, December 31, 2009 and March 31, 2009, and the related gains and/or losses recognized in earnings. The amounts included in the accompanying Condensed Consolidated Balance Sheets and Statements of Income are as follows (in thousands):

	March 31, 2010	December 31, 2009	March 31, 2009
Current derivative assets	$40,541	$25,366	$53,741
Non-current derivative assets	$2,409	$3,090	$2,317
Current derivative liabilities	$17,733	$9,377	$20,422
Non-current derivative liabilities	$(588)	$(733)	$(534)
Cash collateral (receivable)/payable included in derivative assets/liabilities(a)	$(171)	$(2,728)	$3,673
Unrealized gain	$25,634	$17,084	$39,843

(a) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. At March 31, 2010, and December 31, 2009, we had the right to reclaim cash collateral of $0.2 million and $2.7 million, respectively. At March 31, 2009, we had an obligation to return cash collateral of $3.7 million.

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a fair value hedge transaction. 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, 2010, December 31, 2009 and March 31, 2009, the market adjustments recorded in inventory were $(11.0) million, $(0.3) million and $(2.4) 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.

At March 31, 2010, December 31, 2009 and March 31, 2009, we had 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, properly documented 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 other comprehensive income and the ineffective portion is reported in earnings.

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

	March 31, 2010		December 31, 2009		March 31, 2009	
	Crude Oil Swaps/Options	Natural Gas Swaps	Crude Oil Swaps/Options	Natural Gas Swaps	Crude Oil Swaps/Options	Natural Gas Swaps
Notional*	565,500	10,142,050	472,500	9,602,300	450,000	9,946,500
Maximum terms in years**	0.25	0.75	0.25	0.75	0.25	0.75
Current derivative assets	$2,816	$9,151	$3,345	$5,994	$5,189	$18,932
Non-current derivative assets	$220	$3,248	$136	$551	$4,523	$4,764
Current derivative liabilities	$2,655	$53	$1,220	$1,435	$-	$4
Non-current derivative liabilities	$1,428	$-	$2,502	$391	$524	$244
Pre-tax accumulated other comprehensive income (loss) included in balance sheets	$(1,908)	$12,346	$(862)	$4,719	$8,629	$23,448
Earnings	$861	$-	$621	$-	$559	$-

* Crude 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, 2010 market prices, a $7.6 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.

Regulated 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 are as follows:

	Outstanding at March 31, 2010		Outstanding at December 31, 2009		Outstanding at March 31, 2009	
	Notional Amounts*	Latest Expiration (months)	Notional Amounts*	Latest Expiration (months)	Notional Amounts*	Latest Expiration (months)
Natural gas futures purchased	4,740,000	24	6,220,000	15	2,110,000	24
Natural gas options purchased	-	-	1,910,000	3	-	-
Natural gas basis swaps purchased	-	-	225,000	3	-	-

*Gas in MMBtus

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

	March 31, 2010	December 31, 2009	March 31, 2009
Current derivative assets(a)	$1,943	$3,042	$1,581
Non-current derivative assets	$-	$-	$2
Non-current derivative liabilities	$324	$764	$82
Net unrealized loss included in regulatory assets	$6,475	$2,578	$543
Cash collateral included in derivative assets/liabilities(b)	$8,094	$3,789	$2,044

(a) Includes option premium of $0, $1.1 million and $0 at March 31, 2010, December 31, 2009 and March 31, 2009, respectively, which will be recorded as a regulatory asset upon settlement of the options.
(b) At March 31, 2010, December 31, 2009 and March 31, 2009, under master netting agreements we had the right to reclaim cash collateral of $8.1 million, $3.8 million and $2.0 million, respectively.

Weather Hedges

As approved in the State of Iowa, Iowa Gas uses a weather hedge to mitigate the effect of fluctuations from normal weather, but not for trading or speculative purposes. Accounting standards for derivatives require that weather hedges are accounted for by the intrinsic value method which records an asset or liability for the difference between the actual and contracted threshold cooling or heating degree days in the period, multiplied by the contract price. Any gains and losses recorded on the contracts are recorded as regulatory assets or regulatory liabilities, respectively. Anticipated settlements included in Accrued liabilities, other were $1.2 million and $1.0 million at March 31, 2010 and 2009, respectively, on the accompanying Condensed Consolidated Balance Sheets. Anticipated settlements totaling $1.8 million are included in Other current assets on the accompanying Condensed Consolidated Balance Sheet as of December 31, 2009.

Fuel in Storage

At our Electric Utilities, we occasionally hold natural gas in storage for use as fuel for generating electricity with our gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, we occasionally utilize various derivative instruments. These transactions are marked-to-market, designated as cash flow hedges, and recorded in Derivative liabilities, current and Accumulated other comprehensive income on the accompanying Condensed Consolidated Balance Sheet. Gains or losses on these transactions will be recorded in gross margins upon settlement.

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

		March 31, 2010		December 31, 2009	
Notional*		232,500		232,500	
Maximum terms in months		7		10	
Current derivative asset	$	322	$	-	
Current derivative liability	$	-	$	5	
Pre-tax accumulated other comprehensive income (loss)	$	327	$	(5	)

* Gas in MMBtus

Financing Activities

We are exposed to interest rate risk associated with fluctuations in the interest rate on our variable interest rate debt. In order 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, 2010		December 31, 2009		March 31, 2009	
	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	6.75	0.75 (a)	7.0	1.0 (a)	7.75	0.75 (a)
Current derivative liabilities	$ 6,571	$ 41,822	$ 6,342	$ 38,787	$ 5,780	$ 79,677
Non-current derivative liabilities	$ 10,917	$ -	$ 9,075	$ -	$ 20,340	$ -
Pre-tax accumulated other comprehensive income (loss) included in balance sheets	$ (17,488)	$ -	$ (15,417)	$ -	$ (26,120)	$ -
Pre-tax gain (loss) included in Income Statements	$ -	$ (3,035)	$ -	$ 55,653	$ -	$ 14,763

(a) Reflects the amended mandatory early termination dates of the nine and nineteen year 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, 2010 market interest rates and balances related to our $150 million in designated interest rate swaps, a loss of approximately $6.6 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change. Note 14 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 gas marketing in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange 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.

The outstanding forward exchange contracts, which had a fair value of less than $0.1 million at March 31, 2009, were recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. For the three months ended March 31, 2010 and 2009, the unrealized foreign exchange gain was $0.1 million and $0.3 million, respectively. For the three months ended March 31, 2010 and 2009, the realized foreign currency loss was $0.2 million and $0.7 million, respectively. Currency gains or losses on transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Condensed Consolidated Statements of Income as incurred.

(14) 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.

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 as of March 31, 2010, December 31, 2009 and March 31, 2009 (in thousands):

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

Recurring Fair Value Measures	At Fair Value as of December 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral(a)	Total
Assets:					
Commodity derivatives	$-	$154,205	$4,879	$ (117,560)	$41,524
Money market fund	6,000	-	-	-	6,000
Total	$6,000	$154,205	$4,879	$ (117,560)	$47,524
Liabilities:					
Commodity derivatives	$-	$133,604	$5,435	$ (124,078)	$14,961
Interest rate swaps	-	54,204	-	-	54,204
Total	$-	$187,808	$5,435	$ (124,078)	$69,165

Recurring Fair Value Measures	At Fair Value as of March 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral(a)	Total
Assets:					
Commodity derivatives	$ -	$ 340,933	$ 24,926	$ (274,917)	$ 90,942
Foreign currency derivatives	-	107	-	-	107
Total	$ -	$ 341,040	$ 24,926	$ (274,917)	$ 91,049
Liabilities:					
Commodity derivatives	$ -	$ 282,420	$ 11,519	$ (273,288)	$ 20,651
Foreign currency derivatives	-	91	-	-	91
Interest rate swaps	-	105,797	-	-	105,797
Total	$ -	$ 388,308	$ 11,519	$ (273,288)	$ 126,539

(a) Cash collateral on deposit in margin accounts under master netting agreements at March 31, 2010, December 31, 2009 and March 31, 2009 totaled a net $8.3 million, $6.5 million and $(1.6) million, respectively.

The following tables present the changes in level 3 recurring fair value for the three months ended March 31, 2010 and 2009, respectively (in thousands):

		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 relating to instruments still held as of quarter-end	$	1,745	

		Three Months Ended March 31, 2009	
		Commodity Derivatives	
Balance as of beginning of period	$	16,398	
Realized and unrealized losses		(245	)
Purchases, issuance and settlements		(5,307	)
Transfers in and/or out of level 3(a) (b)		2,561	
Balances at end of period	$	13,407	
Changes in unrealized losses relating to instruments still held as of quarter-end	$	(3,442	)

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

(b) Transfers out of level 3 represent existing 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 are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income. We believe an analysis of commodity derivatives classified as level 3 needs to be undertaken with the understanding that these items 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.

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 $8.3 million on deposit in margin accounts at March 31, 2010 to collateralize certain financial instruments, which is included in Derivative assets - 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 agree to the fair value measurements presented in Note 13.

The following table presents the fair value and balance sheet classification of our derivative instruments as of March 31, 2010 and 2009 (in thousands):

Fair Value 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 swap	Derivative liabilities - current	-	41,822
Total derivatives not designated as hedges		$ 225,662	$ 248,328

Fair Value as of March 31, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets – current	$7,339	$4,717
Interest rate swaps	Derivative liabilities – current	—	5,780
Interest rate swaps	Derivative liabilities – non-current	—	20,340
Total derivatives designated as hedges		$7,339	$30,837
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets – current	$343,372	$265,003
Commodity derivatives	Derivative assets – non-current	19,120	7,514
Commodity derivatives	Derivative liabilities – current	11,959	32,320
Commodity derivatives	Derivative liabilities – non-current	170	486
Interest rate swap	Derivative liabilities – current	—	79,677
Foreign currency derivatives	Derivative assets – current	107	26
Foreign currency derivatives	Derivative liabilities – current	—	65
Total derivatives not designated as hedges		$374,728	$385,091

Our derivative activities are discussed in Note 13. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income for the three months ended March 31, 2010.

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 for the three months ended March 31, 2010 and 2009 is presented as follows (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income for the Three Months Ended March 31, 2010 and 2009

Fair Value Hedges

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ 11,208	$ 7,520
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(10,747)	(6,955)
		$ 461	$ 565

33

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income for the three months ended March 31, 2010 and 2009 is presented as follows (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
and the Balance Sheet for the Three Months Ended March 31, 2010

Cash Flow Hedges

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)

The Effect of Derivative Instruments on the Condensed Consolidated Statement of Income
and the Balance Sheet for the Three Months Ended March 31, 2009

Cash Flow Hedges

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 Gain/(Loss) Reclassified 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	$2,115	Interest expense	$(1,348)		$-
Commodity derivatives	7,155	Operating revenue	6,635	Operating revenue	(927)
Total	$9,270		$5,287		$(927)

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 for the three months ended March 31, 2010 and 2009 is presented below (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
for the Three Months Ended March 31, 2010 and 2009

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, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$(2,659)	$(8,125)
Interest rate swap	Interest rate swap - unrealized (loss) gain	(3,035)	14,763
Foreign currency contracts	Operating revenue	-	243
		$(5,694)	$6,881

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments at March 31, 2010 and December 31, 2009 is as follows (in thousands):

	March 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents	$136,023	$136,023	$112,901	$112,901
Restricted cash	$27,215	$27,215	$17,502	$17,502
Derivative financial instruments - assets	$60,650	$60,650	$41,524	$41,524
Derivative financial instruments - liabilities	$80,915	$80,915	$69,165	$69,165
Notes payable	$223,000	$223,000	$164,500	$164,500
Long-term debt, including current maturities	$1,017,940	$1,102,574	$1,051,157	$1,123,703

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 cash held in escrow in accordance with terms of a settlement at our Oil and Gas segment and restricted monies invested in 30-day term deposits as allowed under our project financing agreement at Black Hills Wyoming. The term deposits are recorded at contract value which approximates fair value and due to the short maturity, are considered cash.

Derivative Financial Instruments

These 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 13 and 14.

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 for us to call these bonds.

(16) 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 2009 Annual Report on Form 10-K. Except as described below, there have been no material developments in any previously reported proceedings or any new material proceedings that have developed or material proceedings that have terminated during the first three months of 2010.

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, 2010, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Purchase Power Agreement

In March 2010, Black Hills Power entered into a seven-year PPA and Purchase Option Agreement with the City of Gillette, Wyoming effective April 2010 that replaces a previous agreement. The PPA provides for 23 MW of system-firm electricity capacity and 23 MWh of electric energy per hour on a take-or-pay basis. This PPA also provides the City of Gillette with an option to purchase a 23% ownership interest in Black Hills Power's Wygen III facility which commenced commercial operations on April 1, 2010. As an incentive for the City of Gillette to complete the purchase, the capacity rate is structured to escalate commencing July 2010. In addition, the purchase price would increase on January 1, 2011, and escalate each year throughout the term of the PPA. If the City of Gillette exercises the option, the PPA will terminate upon the closing of the transaction.

(17) INCOME TAXES

Our effective tax rate for the three months ended March 31, 2010 was higher than for the three months ended March 31, 2009 primarily as a result of a positive adjustment in the first quarter of 2009 for a previously recorded tax position. We recorded a $3.8 million reduction in tax expense in our Oil and Gas segment due to a re-measurement of this position in accordance with accounting for uncertain tax positions.

(18) IMPAIRMENT OF LONG-LIVED ASSETS

As a result of lower natural gas prices at March 31, 2009, we recorded a non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment. The lower prices at March 31, 2009 resulted in a $43.3 million pre-tax decrease in the full cost accounting method's ceiling limit for capitalized oil and gas property costs. The write-down in the net carrying value of our natural gas and crude oil properties was recorded as Impairment of long-lived assets and was based on the March 31, 2009 NYMEX price of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and NYMEX price of $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

(19) SALE OF OPERATING ASSETS

In March 2010, Nebraska Gas sold assets to Metropolitan Utilities District as a result of annexation proceedings by the city of Omaha, Nebraska. Nebraska Gas received $6.1 million in cash and recognized a $1.7 million after-tax gain on the sale.

(20) SUBSEQUENT EVENTS

Corporate Credit Facility

On April 15, 2010, we terminated our $525.0 million revolving credit facility and entered into a new $500.0 million revolving credit facility expiring April 14, 2013. The new facility can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. It contains covenants and events of default that are substantially the same as the prior facility. 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. There is a commitment fee of 0.5% based upon current credit ratings on the unused amount of the commitments. The facility contains an accordion feature which allows us to increase the capacity of the facility to $600.0 million. Estimated deferred financing costs of $4.7 million were capitalized and will be amortized over the three-year term of the facility.

Enserco Credit Facility

On May 7, 2010, Enserco entered into an agreement for a two-year $226.5 million committed credit facility. Societe Generale and BNP Paribas are co-lead arranger banks. Enserco is currently negotiating an additional $23.5 million of funding, raising the total committed facility to $250 million. The facility includes a $100 million accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility. This facility replaces the $300 million credit facility which expires on May 7, 2010. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for basic rate borrowings are 1.75% and for Eurodollar borowings are 2.5%.

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 Group	Electric Utilities
	Gas Utilities
Non-regulated Energy Group	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 202,025 customers in South Dakota, Wyoming, Colorado and Montana. In addition, Cheyenne Light, which is also reported within the Electric Utilities segment, provides natural gas to approximately 34,100 customers in Wyoming. Our Gas Utilities segment serves approximately 526,900 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 through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil and related services.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 72.

Significant Events

Wygen III Power Plant

On April 1, 2010, the Wygen III, 110 MW mine-mouth coal-fired power plant commenced commercial operations. Black Hills Power currently owns a 75% interest in the facility.

Smart Grid Funding

In April 2010, we reached an agreement with the Department of Energy for smart grid funding through grants totaling $20.7 million for our Electric Utilities. The funds are made available through the American Recovery and Reinvestment Act of 2009 and combined with matching investments from us will enable our electric utilities to install 149,000 smart meters and make related infrastructure investments.

Purchase Power Agreement

In March 2010, Black Hills Power entered into a seven-year PPA and Purchase Option Agreement with the City of Gillette, Wyoming to provide 23 MW of system-firm electricity capacity and 23 MWh of electric energy per hour, on a take-or-pay basis. The Agreement replaces a previous agreement that expired in April 2010. This PPA also provides the City of Gillette with an option to purchase a 23% ownership interest in Black Hills Power's Wygen III facility which commenced commercial operations on April 1, 2010. As an incentive for the City of Gillette to complete the purchase, the capacity rate is structured to escalate commencing July 2010. In addition, the purchase price would increase on
January 1, 2011 and escalate each year throughout the term of the PPA. If the City of Gillette exercises the option, the PPA will terminate upon the closing of the transaction.

Results of Operations

Executive Summary and Overview

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009. Income from continuing operations for the three months ended March 31, 2010 was $31.4 million, or $0.81 per share, compared to $25.6 million, or $0.66 per share, reported for the same period in 2009. The 2010 income from continuing operations includes a $1.7 million after-tax gain on the sale of assets by Nebraska Gas and a $2.0 million non-cash after-tax mark-to-market loss on certain interest rate swaps. The 2009 income from continuing operations includes a $9.6 million after-tax mark-to-market gain on these same interest rate swaps, a $27.8 million after-tax non-cash ceiling tax impairment, and a $16.9 million after-tax gain on the sale of a 23.5% ownership interest in Wygen I.

Net income was $31.4 million, or $0.81 per share, in the first three months of 2010, compared to $26.4 million, or $0.68 per share, for the same period in 2009. In addition to the items mentioned above in income from continuing operations, the 2009 net income includes $0.8 million of after-tax income from discontinued operations related to the IPP Transaction.

Business Group highlights are as follows:

Utilities Group

The Utilities Group's income from continuing operations for the first three months of 2010 was $29.4 million, compared to $26.6 million for the same period in 2009. Our Electric Utilities were positively impacted by an increase in off-system sales margins and our Gas Utilities recorded increased margins due to favorable weather and the impact of rate proceedings not in effect in the first quarter of 2009. In addition, highlights of our Utilities Group include the following:

- The Wygen III generating facility commenced operations on April 1, 2010. AFUDC-borrowed increased $0.6 million after-tax and AFUDC-equity increased $0.4 million after-tax related to the construction;

- Colorado Electric filed a request with the CPUC on January 6, 2010, seeking a $22.9 million increase in annual revenues, with an anticipated effective date of mid-2010;

- In 2009, Black Hills Power filed a request for revenue increases of $32.0 million with the SDPUC and $3.8 million with the WPSC. Interim rates increased in South Dakota $24.0 million in annual revenues and became effective on April 1, 2010. On May 4, 2010, Black Hills Power filed a settlement stipulation agreement with the WPSC for a $3.1 million increase in annual revenues. Rates are anticipated to be in effect June 1, 2010, subject to WPSC approval;

- We reached agreement with the Department of Energy for smart grid funding through matching grants totaling $20.7 million, made available through the American Recovery and Reinvestment Act of 2009;

- Black Hills Power completed a seven-year PPA with the City of Gillette, Wyoming. This agreement includes an option for Gillette to purchase a 23% ownership interest in Wygen III;

- Plans to construct gas-fired generation to serve Colorado Electric customers are moving forward to start providing energy on January 1, 2012. The 180 MW is expected to cost between $240 million and $260 million; and

- Due to the annexation by the City of Omaha, Nebraska of an outlying suburb, Nebraska Gas sold assets 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. Approximately 3,000 customers in the annexed area were served by Nebraska Gas prior to the sale.

Non-regulated Energy Group

Income from continuing operations was $7.1 million for the first three months of 2010 for the Non-regulated Energy Group compared to a loss from continuing operations of $6.5 million in the same period in 2009. Our Energy Marketing and Oil and Gas segments were impacted significantly by changes in commodity prices. In addition, highlights of the Non-regulated Energy Group include the following:

- The first quarter of 2009 included a $27.8 million after-tax non-cash ceiling test impairment charge due to a write-down in value of our natural gas and crude oil properties resulting from low quarter-end prices for the commodities at our Oil and Gas segment. The write-down of gas and oil properties was based on period-end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil;

- The first quarter of 2009 included a $16.9 million after-tax gain on the sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility at our Power Generation segment;

- Plans to construct gas-fired generation at Colorado IPP to serve the 20-year PPA with Colorado Electric are moving forward to start providing energy on January 1, 2012. The 200 MW project is expected to cost between $240 million and $265 million.

Corporate Segment

Loss from continuing operations was $5.0 million for the first three months of 2010 compared to income from continuing operations of $5.5 million in the same period in 2009.

- We recognized a non-cash mark-to-market loss related to certain interest rate swaps of $2.0 million after-tax for the first three months of 2010 compared to a $9.6 million after-tax gain for the same period in 2009; and

- On April 15, 2010, we entered into a new three-year $500 million Revolving Credit Facility that will be used to fund working capital needs and general corporate purposes. The new facility replaces the existing Corporate Credit Facility, which terminated on April 15, 2010.

Consolidated Results

Revenues, Income (loss) from continuing operations, and Net income (loss) provided by each business group were as follows (in thousands):

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Revenues		
Utilities	$391,806	$393,397
Non-regulated Energy	50,526	44,546
	$442,332	$437,943
Income (loss) from continuing operations		
Utilities	$29,350	$26,582
Non-regulated Energy	7,051	(6,493)
Corporate	(4,967)	5,536
	$31,434	$25,625
Net income (loss)		
Utilities	$29,350	$26,582
Non-regulated Energy	7,051	(5,727)
Corporate	(4,967)	5,536
	$31,434	$26,391

Income from continuing operations increased $5.8 million for the three months ended March 31, 2010 reflecting the following:

Utilities

- A $0.5 million increase in Electric Utilities earnings;
- A $2.2 million increase in the Gas Utilities earnings;

Non-regulated Energy

- A $28.1 million increase in Oil and Gas earnings;
- A $0.5 million increase in Coal Mining earnings;
- A $1.0 million increase in Energy Marketing earnings;
- A $16.1 million decrease in Power Generation earnings; and

Corporate

- A $10.5 million decrease in corporate activities.

The following discussion provides additional detail of the results of operations from our Utilities and Non-regulated Energy Groups by business segment, as well as Corporate activities.

The following business group and segment information does not include intercompany eliminations or results of discontinued operations. Amounts are presented on a pre-tax basis unless otherwise indicated.

Utilities Group

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

Electric Utilities

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(in thousands)	
Revenue - electric	$132,768	$122,177
Revenue - gas	16,041	15,098
Total revenue	148,809	137,275
Fuel and purchased power - electric	73,511	64,896
Purchased gas	11,191	10,258
Total fuel and purchased power	84,702	75,154
Gross margin - electric	59,257	57,281
Gross margin - gas	4,850	4,840
Total gross margin	64,107	62,121
Operating, general and administrative costs	32,768	31,917
Depreciation and amortization	11,189	10,958
Total operating expenses	43,957	42,875
Operating income	20,150	19,246
Interest expense, net	(8,254)	(7,499)
Other income	2,125	1,745
Income tax expense	(4,169)	(4,175)
Income from continuing operations and net income	$9,852	$9,317

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

Sales Revenues	Three Months Ended March 31, 2010	2009
	(in thousands)	
Residential:		
Black Hills Power	$ 14,479	$ 14,281
Cheyenne Light	7,925	7,487
Colorado Electric	19,416	16,503
Total Residential	41,820	38,271
Commercial:		
Black Hills Power	14,539	14,643
Cheyenne Light	12,456	12,061
Colorado Electric	15,690	13,228
Total Commercial	42,685	39,932
Industrial:		
Black Hills Power	4,637	4,750
Cheyenne Light	2,530	2,533
Colorado Electric	6,944	8,092
Total Industrial	14,111	15,375
Municipal:		
Black Hills Power	653	636
Cheyenne Light	231	241
Colorado Electric	1,687	1,029
Total Municipal	2,571	1,906
Contract Wholesale:		
Black Hills Power	6,718	6,553
Off-system Wholesale:		
Black Hills Power	8,716	9,220
Cheyenne Light	2,591	1,980
Colorado Electric	7,333	4,053
Total Off-system Wholesale	18,640	15,253
Other:		
Black Hills Power	4,747	4,375
Cheyenne Light	912	101
Colorado Electric	564	411
Total Other	6,223	4,887
Total Sales Revenues	$ 132,768	$ 122,177

Quantities Generated and Purchased	Three Months Ended March 31, 2010	2009
	(in MWh)	
Generated -		
Coal-fired:		
Black Hills Power	430,573	437,551
Cheyenne Light	176,424	191,556
Colorado Electric	70,251	66,475
Total Coal	677,248	695,582
Gas and Oil-fired:		
Black Hills Power	2,838	1,075
Cheyenne Light	-	-
Colorado Electric	-	-
Total Gas and Oil	2,838	1,075
Total Generated:		
Black Hills Power	433,411	438,626
Cheyenne Light	176,424	191,556
Colorado Electric	70,251	66,475
Total Generated	680,086	696,657
Purchased:		
Black Hills Power	429,682	432,839
Cheyenne Light	192,857	157,987
Colorado Electric	541,202	487,526
Total Purchased	1,163,741	1,078,352
Total Generated and Purchased:		
Black Hills Power	863,093	871,465
Cheyenne Light	369,281	349,543
Colorado Electric	611,453	554,001
Total Generated and Purchased	1,843,827	1,775,009

Quantity Sold	Three Months Ended March 31, 2010	2009
	(in MWh)	
Residential:		
Black Hills Power	174,535	163,476
Cheyenne Light	74,820	71,126
Colorado Electric	167,029	142,673
Total Residential	416,384	377,275
Commercial:		
Black Hills Power	184,438	175,256
Cheyenne Light	145,209	145,545
Colorado Electric	170,954	149,466
Total Commercial	500,601	470,267
Industrial:		
Black Hills Power	86,663	85,984
Cheyenne Light	40,759	42,822
Colorado Electric	84,510	121,814
Total Industrial	211,932	250,620
Municipal:		
Black Hills Power	8,226	8,095
Cheyenne Light	934	1,025
Colorado Electric	15,778	7,420
Total Municipal	24,938	16,540
Contract Wholesale:		
Black Hills Power	168,465	168,679
Off-system Wholesale:		
Black Hills Power	231,047	243,786
Cheyenne Light	84,267	70,104
Colorado Electric	159,775	105,943
Total Off-system Wholesale	475,089	419,833
Total Quantity Sold:		
Black Hills Power	853,374	845,276
Cheyenne Light	345,989	330,622
Colorado Electric	598,046	527,316
Total Quantity Sold	1,797,409	1,703,214
Losses and Company Use:		
Black Hills Power	9,719	26,190
Cheyenne Light	23,292	18,921
Colorado Electric	13,407	26,684
Total Losses and Company Use	46,418	71,795

Total Energy	1,843,827	1,775,009

Degree Days	Three Months Ended March 31,			
	2010		2009	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual -				
Black Hills Power	3,392	3 %	3,254	(1)%
Cheyenne Light	3,110	(1)%	2,824	(10)%
Colorado Electric	2,777	5 %	2,370	(10)%

	Electric Utilities Power Plant Availability	
	Three Months Ended March 31,	
	2010	2009
Coal-fired plants	94.0 %*	97.3 %
Other plants	99.7 %	99.2 %
Total availability	96.2 %	98.0 %

---

* Reflects unplanned twelve-day outage at the Wyodak plant due to a collapsed scrubber vessel.

Cheyenne Light Natural Gas Distribution

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

	Three Months Ended March 31,	
	2010	2009
Sales Revenues (in thousands):		
Residential	$9,513	$9,012
Commercial	4,833	4,429
Industrial	1,458	1,434
Other	237	223
Total Sales Revenues	$16,041	$15,098
Gross Margins (in thousands):		
Residential	$3,252	$3,277
Commercial	1,217	1,171
Industrial	167	169
Other	214	223
Total Gross Margins	$4,850	$4,840

Volumes Sold (Dth):		
Residential	1,139,543	1,015,246
Commercial	661,118	584,423
Industrial	242,175	247,325
Total Volumes Sold	2,042,836	1,846,994

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009. Income from continuing operations was $9.9 million in the first three months of 2010 compared to $9.3 million in the first three months of 2009 as a result of:

Gross margin: Gross margin increased $2.0 million primarily due to a $1.2 million increase in off-system sales margin.

Operating, general and administrative costs: Operating, general and administrative costs were comparable to the same period in the prior year.

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

Interest expense, net: Interest expense, net increased $0.8 million due to higher interest expense of $3.1 million compared to the same period in the prior year as a result of a change in debt structure from short-term debt to longer-term debt, partially offset by an increase of $2.3 million for AFUDC associated with the borrowed funds for the construction at Wygen III and Colorado Electric.

Other income: Other income increased $0.4 million primarily due to increased AFUDC-equity associated with the construction of our Wygen III facility.

Income tax expense: The effective tax rate for the three months ended March 31, 2010 was comparable to the effective tax rate for the three months ended March 31, 2009.

Gas Utilities

Operating results for the Gas Utilities are as follows (in thousands):

	Three Months Ended March 31, 2010	2009
Sales revenue:		
Natural gas - regulated	$235,455	$248,981
Other - non-regulated services	7,715	7,356
Total sales revenue	243,170	256,337
Cost of sales:		
Natural gas - regulated	163,427	181,215
Other - non-regulated services	4,018	4,570
Total cost of sales	167,445	185,785
Gross margin	75,725	70,552
Operating, general and administrative costs	34,358	32,996
Gain on sale of operating assets	(2,683)	-
Depreciation and amortization	7,045	8,181
Total operating expenses	38,720	41,177
Operating income	37,005	29,375
Interest expense, net	(6,185)	(2,235)
Other expense	(211)	(36)
Income tax expense	(11,111)	(9,839)
Income from continuing operations and net income	$19,498	$17,265

The following table summarizes regulated Gas Utilities' sales revenues (in thousands):

Sales Revenues	Three Months Ended March 31, 2010	2009
Residential:		
Colorado	$22,852	$27,410
Nebraska	57,094	59,282
Iowa	48,679	54,545
Kansas	33,344	30,705
Total Residential	161,969	171,942
Commercial:		
Colorado	4,989	5,832
Nebraska	21,410	21,959
Iowa	22,789	25,487
Kansas	11,250	10,416
Total Commercial	60,438	63,694
Industrial:		
Colorado	44	130
Nebraska	1,505	1,513
Iowa	911	617
Kansas	787	1,260
Total Industrial	3,247	3,520
Transportation:		
Colorado	281	176
Nebraska	4,649	3,952
Iowa	1,200	1,100
Kansas	1,938	1,606
Total Transportation	8,068	6,834
Other:		
Colorado	27	29
Nebraska	612	648
Iowa	444	426
Kansas	650	1,888
Total Other	1,733	2,991
Total Regulated	235,455	248,981
Non-regulated Services	7,715	7,356
Total	$243,170	$256,337

51

The following table summarizes regulated Gas Utilities' sales margins (in thousands):

Gross Margin	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Residential:		
Colorado	$6,590	$5,115
Nebraska	16,336	15,135
Iowa	15,455	15,565
Kansas	10,217	9,056
Total Residential	48,598	44,871
Commercial:		
Colorado	1,217	967
Nebraska	5,139	4,744
Iowa	4,613	5,122
Kansas	2,580	2,219
Total Commercial	13,549	13,052
Industrial:		
Colorado	23	35
Nebraska	163	142
Iowa	85	66
Kansas	183	214
Total Industrial	454	457
Transportation:		
Colorado	281	176
Nebraska	4,649	3,952
Iowa	1,200	1,100
Kansas	1,951	1,606
Total Transportation	8,081	6,834
Other:		
Colorado	27	29
Nebraska	612	648
Iowa	444	426
Kansas	263	1,449
Total Other	1,346	2,552
Total Regulated	72,028	67,766
Non-regulated Services	3,697	2,786
Total	$75,725	$70,552

The following table summarizes regulated Gas Utilities' volumes sold (in Dth):

Volumes Sold	Three Months Ended March 31, 2010	2009
Residential:		
Colorado	2,820,847	2,351,614
Nebraska	6,336,387	5,699,778
Iowa	5,393,894	5,465,557
Kansas	3,568,617	2,946,898
Total Residential	18,119,745	16,463,847
Commercial:		
Colorado	655,373	509,478
Nebraska	2,545,124	2,335,660
Iowa	2,908,104	2,822,937
Kansas	1,345,148	1,120,927
Total Commercial	7,453,749	6,789,002
Industrial:		
Colorado	3,754	12,257
Nebraska	219,970	202,481
Iowa	131,266	82,132
Kansas	110,624	189,254
Total Industrial	465,614	486,124
Transportation:		
Colorado	298,543	234,974
Nebraska	7,990,628	7,583,683
Iowa	5,312,748	4,067,274
Kansas	4,209,828	3,492,627
Total Transportation	17,811,747	15,378,558
Other:		
Colorado	-	-
Nebraska	976	890
Iowa	42,297	36,173
Kansas	59,009	59,582
Total Other	102,282	96,645
Total Regulated	43,953,137	39,214,176

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 %

Degree Days	Three Months Ended March 31, 2009	
Heating Degree Days:	Actual	Variance From Normal
Colorado	2,524	(12)%
Nebraska	2,979	(6)%
Iowa	3,439	(1)%
Kansas*	2,202	(14)%
Combined Gas Utilities Heating Degree Days	3,013	(6)%

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

Our Gas Utilities are highly seasonal and sales volumes depend largely on 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, 2010 Compared to Three Months Ended March 31, 2009. Income from continuing operations was $19.5 million in the first three months of 2010 compared to $17.3 million in the first three months of 2009 as a result of:

Gross margin: Gross margins increased $5.2 million due to higher volumes on more heating degree days and increased rates approved at Iowa Gas, Nebraska Gas and Colorado Gas that were not in effect in the first quarter of 2009.

Operating, general and administrative costs: Operating, general and administrative costs increased $1.4 million primarily due to increases in employee benefits and property taxes.

Gain on sale of operating assets: The gain on sale of operating assets of $2.7 million represents assets sold by Nebraska Gas as a result of territory annexed by the City of Omaha, Nebraska.

Depreciation and amortization: Depreciation and amortization decreased $1.1 million primarily due to assets that became fully depreciated during 2009.

Interest expense, net: Interest expense, net increased $4.0 million primarily resulting from the assignment of debt to reflect an appropriate capital structure and an increased interest rate reflecting the assignments of long-term debt.

Other expense: Other expense is comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the three months ended March 31, 2010 was comparable to the effective tax rate for the three months ended March 31, 2009.

Regulatory Matters – Utilities Group

The following summarizes our recent rate case 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	11/2006	9/2007	$ 16.3	$ 9.2	10.4 %	51.0 %	49.0 %
Nebraska Gas (2)	Gas	12/2009	Pending	$ 12.1	Pending	Pending	Pending	Pending
Iowa Gas (3)	Gas	6/2008	7/2009	$ 13.6	$ 10.8	10.1 %	51.4 %	48.6 %
Colorado Gas (4)	Gas	6/2008	4/2009	$ 2.7	$ 1.4	10.3 %	50.5 %	49.5 %
Kansas Gas (5)	Gas	5/2009	10/2009	$ 0.5	$ 0.5	10.2 %	50.7 %	49.3 %
Black Hills Power (6)	Electric	9/2008	1/2009	$ 4.5	$ 3.8	10.8 %	57.0 %	43.0 %
Black Hills Power (7)	Electric	9/2009	Pending	$ 32.0	Pending	Pending	Pending	Pending
Black Hills Power (8)	Electric	10/2009	Pending	$ 3.8	Pending	Pending	Pending	Pending
Colorado Electric (9)	Electric	1/2010	Pending	$ 22.9	Pending	Pending	Pending	Pending

(1) In November 2006, Nebraska Gas filed for a $16.3 million rate increase. Interim rates were implemented in February 2007 and, in July 2007, the NPSC granted a $9.2 million increase in annual revenues based on an equity return of 10.4% on a capital structure of 51% equity and 49% debt. Nebraska Gas appealed the decision, and the district court affirmed the NPSC order in February 2008. Because Nebraska Gas collected interim rates subject to refund, it was required to refund to customers the difference between the higher interim rates and the final rates plus interest (approximately $5.6 million). The NPA appealed one aspect of our refund plan worth approximately $0.8 million. On April 15, 2009, the District Court affirmed the NPSC refund plan order, and thereby rejected NPA's appeal.

(2) On December 1, 2009, Nebraska Gas filed with the NPSC for a $12.1 million rate case requesting a gas revenue increase to recover increased operating costs and distribution system investments. The proposed increase in revenues is about 6.5%. Interim rates subject to refund for the entire amount of the proposed increase went into effect on March 1, 2010. Hearings before the NPSC have been scheduled to begin May 24, 2010. A commission decision is anticipated by mid-August 2010.

(3) On June 3, 2009, Iowa Gas received approval from the IUB to implement new natural gas service rates for its Iowa residential, commercial and industrial customers. The rates went into effect on July 27, 2009. The approved rates allow Iowa Gas to recover capital investments made in its natural gas distribution system and offset increasing operating costs due to inflation since the last rate increase in March 2006. The new rates represent approximately $10.8 million in additional revenue. The increase is based on a return on equity of 10.1%, with a capital structure of 51.4% equity and 48.6% debt.

(4) In June 2008, Colorado Gas filed for a $2.7 million rate increase. The increase was based on a proposed equity return of 11.5% on a capital structure of 50% equity and 50% debt. Interim rates were not available for collection in Colorado. On September 19, 2008, Colorado Gas filed the second phase of its rate request. On January 29, 2009, a settlement agreement was filed with the CPUC and a settlement was approved with new rates effective on April 1, 2009. The new rates included an increase in annual revenues of $1.4 million, which was based on a 10.25% return on equity with a capital structure of 50.48% equity and 49.52% debt.

(5) Kansas Gas has requested a GSRS in the amount of $0.5 million annually. The KCC issued an order on September 14, 2009 approving the request for $0.5 million and allowing Kansas Gas to continue collecting the $0.3 million previously authorized. The new rates had an effective date of October 1, 2009.

(6) On February 10, 2009, the FERC approved a formulaic approach to the method used to determine the revenue component of Black Hills Power's open access transmission tariff, and increased the utility's annual transmission revenue requirement by approximately $3.8 million. The revenue requirement is based on an equity return of 10.8%, and a capital structure consisting of 57% equity and 43% debt. The new rates had an effective date of January 1, 2009.

(7) On September 30, 2009, Black Hills Power filed a rate case with the SDPUC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred during the past four years. Black Hills Power is seeking a $32.0 million, or 26.6%, increase in annual utility revenues. In March 2010, the SDPUC approved interim rates for a 20% increase in rates effective April 1, 2010 for South Dakota customers. The proposed rate increase is subject to approval by the SDPUC.

(8) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred since 1995. Black Hills Power is seeking a $3.8 million, or 38.95%, increase in annual utility revenues. On May 4, 2010, Black Hills Power filed a settlement stipulation agreement with the WPSC for a $3.1 million increase in annual revenues. Rates are anticipated to be in effect June 1, 2010. The proposed rate increase is subject to approval by the WPSC.

(9) On January 6, 2010, Colorado Electric filed a rate case with CPUC requesting an electric revenue increase to recover increased operating expenses associated with electricity supply contracts, investment in equipment and electricity distribution facilities necessary to maintain and strengthen the reliability of the electric delivery system in Colorado. Colorado Electric is seeking a $22.9 million, or approximately 12.8%, increase in annual revenues with an anticipated effective date of mid-2010. The proposed increase is subject to CPUC approval.

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, 2010	Three Months Ended March 31, 2009
Revenue	$19,743	$16,511
Operating, general and administrative costs	9,734	10,020
Depreciation, depletion and amortization	6,111	8,941
Impairment of long-lived assets	-	43,301
Total operating expenses	15,845	62,262
Operating income (loss)	3,898	(45,751)
Interest expense	(782)	(1,041)
Other income	303	162
Income tax (expense) benefit	(1,071)	20,910
Income (loss) from continuing operations and net income (loss)	$2,348	$(25,720)

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Fuel production:		
Bbls of oil sold	84,391	99,370
Mcf of natural gas sold	2,152,176	2,688,890
Mcf equivalent sales	2,658,522	3,285,110

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Average price received: (a)		
Gas/Mcf (b) (c)	$5.91	$4.91
Oil/Bbl	$74.39	$50.42
Depletion expense/Mcfe	$2.00	$2.49

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids
(c) Does not include the negative revenue impacts of a $1.2 million royalty settlement accrual for March 31, 2009, resulting in a $0.48/Mcf price impact

The following are summaries of LOE/Mcfe:

	Three Months Ended March 31, 2010			Three Months Ended March 31, 2009		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$1.43	$ 0.37	$1.80	$1.22	$ 0.26	$1.48
Colorado	0.53	0.81	1.34	0.74	0.46	1.20
Wyoming	1.49	-	1.49	1.42	-	1.42
All other properties(a)	0.94	0.07	1.01	0.97	0.10	1.07
All locations(a)	$1.25	$ 0.25	$1.50	$1.17	$ 0.17	$1.34

(a) During the first quarter of 2010, our Oil and Gas segment transferred midstream assets to a new subsidiary in our Energy Marketing segment. As a result, 2009 Gathering, Compression and Processing have been modified to reflect the removal of these assets for comparability purposes.

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009. Income from continuing operations increased $28.1 million for the three months ended March 31, 2010 compared to the same period in 2009 primarily due to:

Revenue: Revenues increased $3.2 million due to a 20% increase in the average hedged price of natural gas and a 48% increase in average hedged price of oil, partially offset by a 15% decline in oil volumes and a 20% decline in gas volumes. The production variance was largely driven by natural declines from producing properties partially offset by moderate drilling capital deployment.

Operating, general and administrative costs: Lower operating costs realized through cost containment efforts were partially offset by higher production taxes due to the increases in price.

Depreciation, depletion and amortization: Depreciation, depletion and amortization decreased $2.8 million due to lower volumes and a lower depletion rate. The lower depletion rate for the three months ended March 31, 2010 compared to the same period in the prior year is a result of the reduction in the depletion cost base due to the previous impairment charges and the increase in proved reserve estimates as of March 31, 2010 due to higher prices.

Impairment of long-lived assets: A $27.8 million after-tax non-cash ceiling test impairment charge was taken during the first quarter of 2009. The write-down in the net carrying value of our natural gas and crude oil properties resulted from low March 31, 2009 quarter-end prices for the commodities. The write-down of gas and oil properties was based on period-end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Interest expense, net: Interest expense, net decreased $0.3 million primarily due to a reduction in intercompany debt and lower intercompany interest rates.

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

Income tax expense: Income tax expense was recorded in the first three months of 2010 due to pre-tax earnings compared to an income tax benefit in the first three months of 2009 resulting from the impairment charge and a $3.8 million positive adjustment of a previously recorded tax position.

Coal Mining

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Revenue	$13,980	$14,402
Operating, general and administrative costs	10,241	10,196
Depreciation, depletion and amortization	2,890	3,986
Total operating expenses	13,131	14,182
Operating income	849	220
Interest income, net	318	311
Other income	556	202
Income tax (expense) benefit	(377)	86
Income from continuing operations and net income	$1,346	$819

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

	Three Months Ended March 31, 2010	2009
Tons of coal sold	1,392	1,506
Cubic yards of overburden moved	3,571	3,162

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009.
Income from continuing operations increased $0.5 million for the three months ended March 31, 2010 compared to the same period in 2009, primarily due to:

Revenue: Revenue decreased $0.4 million due to an 8% decrease in tons of coal sold as a result of outages at customers' power plants, partially offset by an increase of approximately 5% in average price received. The higher average price received reflects the impact of regulated sales prices determined in part by a return on depreciable asset components.

Operating, general and administrative costs: Lower equipment costs and royalties were offset by increased overburden removal costs. Cubic yards of overburden moved increased 13%.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense decreased approximately $1.1 million due to lower estimated future reclamation costs amortized over the life of the coal mine inventory, partially offset by increased depreciation on buildings and equipment. The asset value of unrestricted coal inventory is amortized over the life of the coal mine inventory. Due to a 2009 modification, there was a significant reduction to the asset base for the coal mine inventory which lowered depreciation.

Interest income, net: Interest income, net for 2010 was comparable to interest income, net in 2009.

Other income: Other income increased $0.4 million primarily due to income from a site lease for the Wygen III power plant which is located on mine property.

Income tax expense: Income tax expense increased due to higher pre-tax earnings during the first three months of 2010. During the first three months of 2009, the tax benefit generated by percentage depletion had a more significant effect on income tax provision.

Energy Marketing

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(in thousands)	
Revenue -		
Realized gas marketing gross margin	$10,521	$10,971
Unrealized gas marketing gross margin	(1,004)	(1,336)
Realized oil marketing gross margin	1,532	2,977
Unrealized oil marketing gross margin	(1,277)	(5,792)
Total margin	9,772	6,820
Operating, general and administrative costs	5,426	5,130
Depreciation and amortization	132	133
Total operating expenses	5,558	5,263
Operating income	4,214	1,557
Interest (expense) income, net	(762)	58
Other (expense) income	(31)	14
Income tax expense	(1,228)	(592)
Income from continuing operations and net income	$2,193	$1,037

The following is a summary of average daily volumes marketed:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Natural gas physical sales - MMBtus	1,753,200	2,252,800
Crude oil physical sales - Bbls	13,430	11,060

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009. Income from continuing operations increased $1.2 million for the three months ended March 31, 2010 compared to the same period in 2009, primarily due to:

Revenue: Revenue increased $3.0 million primarily due to $4.8 million decreased losses on unrealized marketing margins due to fewer trades with a positive value in the forward book going to settlement, partially offset by a decrease of $1.9 million in realized margins on lower crude oil margins as a result of winter weather conditions.

Operating, general and administrative costs: Operating, general and administrative costs increased $0.3 million primarily due to increased bank fees as a result of higher letter of credit costs on a comparable utilization level.

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

Interest (expense) income, net: Interest (expense) income, net increased $0.8 million primarily due to increased amortization of financing costs related to the committed Enserco Credit Facility.

Other (expense) income: Other (expense) income for the first three months of 2010 was comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the three months ended March 31, 2010 is comparable to the effective tax rate for the three months ended March 31, 2009.

Power Generation

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Revenue	$8,068	$7,619
Cost of sales	1,687	1,298
Gross margin	6,381	6,321
Operating, general and administrative costs	1,687	1,642
Depreciation and amortization	1,028	906
Gain on sale of operating asset	-	(25,971)
Total operating expense (income)	2,715	(23,423)
Operating income	3,666	29,744
Interest expense, net	(1,997)	(2,983)
Other expense	(11)	(385)
Income tax expense	(578)	(9,223)
Income from continuing operations and net income	$1,080	$17,153

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

	Three Months Ended March 31, 2010		2009	
Contracted power plant fleet availability:				
Coal-fired plant	100.0	%	95.5	%
Natural gas-fired plants	100.0	%	98.0	%
Total availability	100.0	%	96.6	%

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009. Income from continuing operations decreased $16.1 million for the three months ended March 31, 2010 compared to the same period in 2009 primarily due to:

Revenue: Revenue for the first three months of 2010 was comparable to the first three months of 2009.

Cost of Sales: Cost of sales for the first three months of 2010 was comparable to the first three months of 2009.

Operating, general and administrative costs: Operating expenses were comparable to the same period in the prior year.

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

Gain on sale of operating asset: The gain on sale of operating asset of $26.0 million in the prior period represents the sale of a 23.5% ownership interest to MEAN in the Wygen I generating facility.

Interest expense, net: Interest expense, net decreased $1.0 million primarily due to a decrease in debt from an intercompany debt restructuring offset by the $120.0 million project financing at Black Hills Wyoming.

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

Income tax expense: The effective tax rate for the three months ended March 31, 2010 is comparable to the effective tax rate for the three months ended March 31, 2009.

Corporate

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009. Loss from continuing operations increased $10.5 million primarily due to:

- Unrealized net, mark-to-market losses for the quarter ended March 31, 2010 of approximately $3.0 million on certain interest rate swaps compared to a $14.8 million mark-to-market gain on certain interest rate swaps in the prior period; and
- A $1.1 million decrease in net interest expense.

Discontinued Operations

Earnings from discontinued operations were $0.8 million, net of tax, for the three month period ended March 31, 2009 relating to working capital and tax adjustments associated with the IPP Transaction.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2009 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 2009 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the three month period ended March 31, 2010, we generated sufficient cash flow from operations to meet our operating needs, fund a portion of our property, plant and equipment additions and to pay dividends on our common stock. We plan to fund future property and investment additions including generation for Colorado Electric from internally generated cash resources and external financings.

Cash flows from operations of $88.9 million for the three month period ended March 31, 2010 represent a $111.4 million decrease compared to the same period in the prior year. The change in cash provided by operating activities was due to a $5.8 million increase in income from continuing operations and changes in working capital as follows:

- An $84.8 million decrease in cash flows from working capital changes. This decrease primarily resulted from a $44.1 million decrease in cash flows from lower materials, supplies and fuel, a $99.9 million decrease from changes in accounts receivable and other current assets and a $59.3 million increase from accounts payable and other current liabilities. Changes in materials, supplies and fuel primarily relate to natural gas held in storage by Energy Marketing and the Gas Utilities which fluctuates based on seasonal trends and economic decisions reflecting current market conditions;

and adjusted for non-cash charges and other changes in operating items as follows:

- A $4.9 million decrease in depreciation, depletion and amortization expense;

- In 2009, an adjustment of $43.3 million for the non-cash ceiling test impairment charges to write down the net carrying value of our natural gas and crude oil properties due to low year-end commodity prices.

- A $7.7 million decrease in cash flows from the net change in derivative assets and liabilities primarily from derivatives associated with normal operations of our gas and oil marketing business and our Oil and Gas segment related to commodity price fluctuations;

- A $2.7 million decrease in 2010 to adjust for the non-cash effect of the gain on sale of operating assets, which relates to the sale of gas utility assets in Nebraska compared to a $26.0 million gain in 2009 related to the sale of a 23.5% ownership interest in Wygen III;

- A $17.8 million increase to adjust for the non-cash effect of unrealized mark-to-market losses on interest rate swaps; and

- An $8.9 million increase in cash flows related to changes in deferred income taxes which is primarily due to tax benefits generated by the 2009 oil and gas assets impairment charge.

During the three months ended March 31, 2010, we had cash outflows from investing activities of $78.1 million, which were primarily due to the following:

- Cash outflows of $81.3 million for property, plant and equipment additions. These outflows include approximately $9.7 million related to the construction of our Wygen III power plant, which began commercial operations on April 1, 2010, approximately $39.2 million for construction of 380 MW of natural gas-fired electric generation in Colorado, approximately $5.9 million in oil and gas property maintenance capital and development drilling, and approximately $9.4 million for new transmission at the Electric Utilities; and

- Cash inflows of $6.1 million of proceeds from the sale of gas utility assets in Nebraska.

During the three months ended March 31, 2010, we had net cash outflows from financing activities of $12.3 million primarily resulting from:

- A $58.5 million inflow for net borrowings on the Corporate Credit Facility;

- A $14.1 million outflow for payments of cash dividends on common stock; and

- A $33.2 million outflow from long-term debt payments including $32.5 million for the Series AC bonds and the Series Y bonds.

Dividends

Dividends paid on our common stock totaled $14.1 million for the three months ended March 31, 2010, or $0.36 per share. On April 27, 2010, our Board of Directors declared a quarterly dividend of $0.36 per share payable June 1, 2010, which is equivalent to an annual dividend rate of $1.44 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 our availability under our Corporate Credit Facility described below, as of March 31, 2010, we had approximately $136.0 million of cash unrestricted for operations.

Corporate Credit Facility

Our $525.0 million Corporate Credit Facility was terminated on April 15, 2010 in conjunction with entering into a new three-year Revolving Credit Agreement, as discussed below. The cost of borrowings or letters of credit issued under the Corporate Credit Facility existing at March 31, 2010 was determined based on our credit ratings. At our current ratings levels, the Corporate Credit Facility had an annual facility fee of 17.5 basis points, and had a borrowing spread of 70 basis points over LIBOR (which equates to a 0.95% one-month borrowing rate as of March 31, 2010).

Our Corporate Credit Facility can be used to fund our working capital needs and for general corporate purposes. At March 31, 2010, we had borrowings of $223.0 million and $46.3 million of letters of credit issued on our Corporate Credit Facility. Available capacity remaining on our Corporate Credit Facility was approximately $255.7 million at March 31, 2010.

On April 15, 2010, we terminated our $525.0 million Corporate Credit Facility and entered into a new $500.0 million Revolving Credit Facility expiring April 14, 2013. The new 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. There is a commitment fee of 0.5% based upon current credit ratings on the unused amount of the commitments. The facility contains an accordion feature which allows us to increase the capacity of the facility to $600.0 million. Estimated deferred financing costs of $4.7 million were capitalized and will be amortized over the three-year term of the facility.

The new 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 the following financial covenants: (i) consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income, if positive, beginning January 1, 2005 and (ii) a recourse leverage ratio not to exceed 0.65 to 1.00. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding.

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 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.

Under the Corporate Credit Facility, our consolidated net worth was $1,108.0 million at March 31, 2010, which was approximately $283.1 million in excess of the net worth we were required to maintain under the credit facility. At March 31, 2010, our long-term debt ratio was 47.3%, our total debt leverage ratio (long-term debt and short-term debt) was 52.8%, and our recourse leverage ratio was approximately 54.7%. Our interest expense coverage ratio for the twelve month period ended March 31, 2010 was 3.7 to 1.0. The ratios under the new Revolving Credit Facility are the same with the exception of the interest expense coverage ratio which is not required.

Enserco Credit Facility

In May 2009, Enserco entered into an agreement for a $300 million committed credit facility, which expired on May 7, 2010. At March 31, 2010, $101.8 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

On May 7, 2010, Enserco entered into an agreement for a two-year $226.5 million committed credit facility. Enserco is currently negotiating an additional $23.5 million of funding, raising the total committed facility to $250 million. The facility includes a $100 million accordion feature which allows us to increase commitments under the facility. Societe Generale and BNP Paribas are co-lead arranger banks. The Bank of Tokyo Mitsubishi UFJ, Raiffeisen-Boerenleenbank BA (Rabobank), RZB Finance and U.S. Bank are participating banks. This facility replaces the $300 million credit facility which expired on May 7, 2010. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%.

Black Hills Power

In February 2010, the Black Hills Power Series AC bonds matured. These were paid in full for $30.0 million plus accrued interest of $1.2 million.

In February 2010, Black Hills Power provided notice to the bondholders of its intent to call the Series Y bonds in full. These bonds were originally due in 2018. A total of $2.7 million was paid on March 31, 2010, which includes the balance of $2.5 million plus accrued interest and an early redemption premium of 2.6%.

In April 2010, Black Hills Power provided notice to the bondholders of its intent to call the Series Z bonds in full. These bonds, originally due in 2021, will be paid in full for $19.2 million on May 31, 2010 for principal of $18.3 million, accrued interest and an early redemption premium of 4.675%.

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

Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of March 31, 2010, the restricted net assets at our Electric and Gas Utilities were approximately $214.5 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, we may be restricted from making dividends from Enserco to the parent company of Enserco. The restricted net assets at March 31, 2010 at Enserco were $113.5 million.

Future Financing Plans

We have an effective shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our finance arrangements and restrictions imposed by federal and state regulatory authorities.

We have substantial capital expenditures in 2010 and 2011, which are primarily due to the construction of additional generation to serve our Colorado Electric Utility. 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 maintain a consolidated debt-to-capitalization level in the range of 50% to 55%. We expect to complete long-term senior unsecured debt financing at the holding company level in 2010 or 2011; a portion of the long-term financings may be completed at certain subsidiaries. We also intend to complete a portion of the permanent financing through the issuance of common stock to maintain our target debt-to-capitalization level.

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 $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. For the three months ended March 31, 2010, we recorded a $3.0 million pre-tax unrealized mark-to-market non-cash loss on the swaps. The mark-to-market value on these swaps was a liability of $41.8 million at March 31, 2010. 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 are for terms of ten and twenty years and have amended mandatory early termination dates ranging from December 15, 2010 to December 29, 2010. 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 $150.0 million notional amount floating-to-fixed interest rate swaps, having a maximum remaining term of 6.75 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 $17.5 million at March 31, 2010.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2009 Annual Report on Form 10-K filed with the SEC.

68

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, 2010, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

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

In addition, the first mortgage bonds issued by Black Hills Power were rated at March 31, 2010 as follows:

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

Capital Requirements

During the three months ended March 31, 2010, capital expenditures were approximately $81.3 million for property, plant and equipment additions. We currently expect total capital expenditures in 2010 to approximate $477.4 million.

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

	Three Months Ended March 31, 2010 Expenditures	Total 2010 Planned Expenditures
Utilities:		
Electric Utilities (1)(2) (3)	$ 43,528	$ 277,360
Gas Utilities	2,063	56,480
Non-regulated Energy:		
Oil and Gas(4)	3,699	38,320
Power Generation(5)	21,496	86,300
Coal Mining	3,109	16,540
Energy Marketing(6)	113	2,400
Corporate	6,185	-
	$ 80,193	$ 477,400

(1) During the first quarter of 2010, construction of our Wygen III coal-fired plant was completed at an estimated cost of $186.0 million, which reflects our current 75% ownership interest in the plant. During the first quarter of 2010, our share of the construction costs were $9.7 million.

(2) Electric Utilities planned capital expenditures include approximately $34.3 million for transmission projects in 2010 (excluding transmission related to the 180 MW at Colorado Electric) of which $9.4 million was spent in the first quarter of 2010.

(3) The 2010 total planned expenditures include capital requirements associated with our plans to build 180 MW gas-fired power generation facilities to serve our Colorado Electric customers. We expect to spend capital of $142.3 million in 2010 particularly related to the commitment to purchase the turbine generators from GE and transmission. We spent $18.7 million during the first quarter of 2010. The total construction cost is expected to be approximately $240 million to $260 million to be completed by the end of 2011.

(4) Development capital for our oil and gas properties is expected to be limited to no more than the cash flows produced by those properties. Commodity prices will impact our planned development capital expenditures.

(5) Our Power Generation segment was awarded the bid to provide 200 MW of power for a twenty year period to Colorado Electric. The total construction cost of the new facilities is expected to be approximately $240 million to $265 million which is expected to be completed by the end of 2011. We expect to spend approximately $80.0 million in 2010 and we spent $21.2 million during the first quarter of 2010.

(6) In addition, during the first quarter of 2010, our Oil and Gas segment transferred $3.5 million in midstream assets to our Energy Marketing segment to a new subsidiary, Enserco Midstream, LLC. During 2010, we anticipate that an additional $2.0 million will be invested in capital purchases.

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

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment decreased $4.2 million from $97.7 million at December 31, 2009 to $93.5 million at March 31, 2010. Approximately $56.5 million of the firm transportation and storage fee obligations relate to the 2010-2012 period with the remaining occurring thereafter.

Guarantees

There have been no new guarantees provided from those previously disclosed in Note 20 to our Consolidated Financial Statements in our Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the new pronouncements reported in our 2009 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 affect 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 forward-looking statements include the factors discussed above, the risk factors described in Item 1A. of our 2009 Annual Report on Form 10-K previously filed with the SEC, and other reports that we file with the SEC from time to time, and the following:

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

§ Our ability to access the bank loan and debt capital markets depends on market conditions beyond our control. If the credit 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 $0.1 million and $32.5 million for the remainder of 2010 and for 2011, 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 $477.4 million of capital expenditures in 2010. Some important factors that could cause actual costs 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 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.

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. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism 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):

	March 31, 2010	December 31, 2009
Net derivative liabilities	$ (6,475)	$ (1,511)
Cash collateral	8,094	3,789
	$ 1,619	$ 2,278

74

Non Regulated Trading Activities

The following table provides a reconciliation of activity in our natural gas and crude oil 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, 2010 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2009	$19,521	(a)
Net cash settled during the period on positions that existed at December 31, 2009	(9,922)	
Unrealized gain on new positions entered during the period and still existing at March 31, 2010	3,814	
Realized loss on positions that existed at December 31, 2009 and were settled during the period	1,733	
Change in cash collateral	(2,557)	
Unrealized gain on positions that existed at December 31, 2009 and still exist at March 31, 2010	2,177	
Total fair value of energy marketing positions at March 31, 2010	$14,766	(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):

	March 31, 2010	December 31, 2009
Net derivative assets	$ 25,634	$ 17,084
Cash collateral	171	2,728
Market adjustment recorded in material, supplies and fuel	(11,039)	(291)
Total fair value of energy marketing positions marked-to-market	$ 14,766	$ 19,521

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 2009 Annual Report on Form 10-K and Note 13 and Note 14 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	$101	$70	$171
Level 1	-	-	-
Level 2	23,079	2,515	25,594
Level 3	40	-	40
Market value adjustment for inventory (see footnote (a) above)	(11,039)	-	(11,039)
Total fair value of our energy marketing positions	$12,181	$2,585	$14,766

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative under accounting for derivatives and hedging. Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas and crude oil 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 does 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, 2010 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)	$14,766
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	(17,063)
Fair value of all forward positions (non-GAAP)	(2,297)
Cash collateral included in GAAP marked-to-market fair value	(171)
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$(2,468)

* 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 GAAP measure alone.

There have been no material changes in market risk compared to those reported in our 2009 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 2009 Annual Report on Form 10-K, and Note 13 of the Notes to our Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

76

Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2010, 2011 and 2012 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	04/09/2008	Swap	04/10 - 06/10	5,000	$7.26
San Juan El Paso	04/30/2008	Swap	04/10 - 06/10	2,500	$7.65
AECO	08/20/2008	Swap	04/10 - 06/10	1,000	$7.73
San Juan El Paso	08/20/2008	Swap	07/10 - 09/10	5,000	$7.74
AECO	08/20/2008	Swap	07/10 - 09/10	1,000	$7.88
AECO	10/24/2008	Swap	10/10 - 12/10	1,000	$7.05
San Juan El Paso	12/19/2008	Swap	04/10 - 06/10	1,500	$5.39
San Juan El Paso	12/19/2008	Swap	07/10 - 09/10	3,000	$5.95
San Juan El Paso	12/19/2008	Swap	10/10 - 12/10	5,000	$5.89
CIG	01/26/2009	Swap	04/10 - 06/10	2,000	$4.45
CIG	01/26/2009	Swap	07/10 - 09/10	2,000	$4.47
CIG	01/26/2009	Swap	10/10 - 12/10	2,000	$4.68
CIG	01/26/2009	Swap	01/11 - 03/11	2,000	$6.00
NWR	01/26/2009	Swap	01/11 - 03/11	2,000	$6.05
San Juan El Paso	01/26/2009	Swap	01/11 - 03/11	5,000	$6.38
San Juan El Paso	02/13/2009	Swap	01/11 - 03/11	2,500	$6.16
San Juan El Paso	02/13/2009	Swap	10/10 - 12/10	3,000	$5.35
NWR	02/13/2009	Swap	04/10 - 12/10	1,000	$4.20
AECO	03/04/2009	Swap	01/11 - 03/11	1,000	$5.95
NWR	03/04/2009	Swap	04/10 - 06/10	1,000	$4.06
NWR	03/04/2009	Swap	07/10 - 09/10	1,000	$4.12
NWR	03/04/2009	Swap	10/10 - 12/10	1,000	$4.55
San Juan El Paso	06/02/2009	Swap	04/11 - 06/11	5,000	$5.99
AECO	06/02/2009	Swap	04/11 - 06/11	800	$5.89
NWR	06/02/2009	Swap	04/11 - 06/11	1,500	$5.54
San Juan El Paso	06/25/2009	Swap	04/11 - 06/11	2,500	$5.55
CIG	06/25/2009	Swap	04/11 - 06/11	1,750	$5.33
CIG	09/02/2009	Swap	07/11 - 09/11	500	$5.32
NWR	09/02/2009	Swap	07/11 - 09/11	500	$5.32
San Juan El Paso	09/02/2009	Swap	07/11 - 09/11	2,500	$5.54
CIG	09/25/2009	Swap	07/11 - 09/11	500	$5.59
NWR	09/25/2009	Swap	07/11 - 09/11	1,000	$5.59
AECO	09/25/2009	Swap	07/11 - 09/11	500	$5.76
San Juan El Paso	09/25/2009	Swap	07/11 - 09/11	5,000	$5.91
San Juan El Paso	10/09/2009	Swap	04/10 - 06/10	750	$5.29
San Juan El Paso	10/09/2009	Swap	07/10 - 09/10	1,000	$5.65
San Juan El Paso	10/09/2009	Swap	10/10 - 12/10	1,000	$5.90
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
San Juan El Paso	10/23/2009	Swap	01/11 - 03/11	1,000	$6.59
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	01/08/2010	Swap	01/12 - 03/12	2,500	$6.38
NWR	01/08/2010	Swap	01/12 - 03/12	1,500	$6.47
AECO	01/08/2010	Swap	01/12 - 03/12	500	$6.32
CIG	01/08/2010	Swap	01/12 - 03/12	1,500	$6.43
San Juan El Paso	01/25/2010	Swap	01/12 - 03/12	5,000	$6.44

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	03/19/2010	Swap	07/11 - 09/11	500	$5.19
San Juan El Paso	03/19/2010	Swap	04/12 - 06/12	7,000	$5.27
CIG	03/19/2010	Swap	04/12 - 06/12	1,500	$5.17
NWR	03/19/2010	Swap	04/12 - 06/12	1,500	$5.20
AECO	03/19/2010	Swap	04/12 - 06/12	250	$5.15

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	04/09/2008	Swap	04/10 - 06/10	5,000	$99.60
NYMEX	04/30/2008	Put	04/10 - 06/10	5,000	$85.00
NYMEX	05/29/2008	Put	04/10 - 06/10	5,000	$105.00
NYMEX	07/16/2008	Swap	04/10 - 06/10	5,000	$135.10
NYMEX	07/16/2008	Swap	07/10 - 09/10	5,000	$134.90
NYMEX	08/20/2008	Put	07/10 - 09/10	5,000	$90.00
NYMEX	09/03/2008	Put	07/10 - 09/10	5,000	$90.00
NYMEX	10/24/2008	Put	07/10 - 09/10	5,000	$60.00
NYMEX	12/05/2008	Swap	10/10 - 12/10	5,000	$65.20
NYMEX	01/26/2009	Swap	10/10 - 12/10	5,000	$60.15
NYMEX	01/26/2009	Swap	01/11 - 03/11	5,000	$60.90
NYMEX	02/13/2009	Swap	01/11 - 03/11	5,000	$60.05
NYMEX	03/04/2009	Swap	10/10 - 12/10	5,000	$55.80
NYMEX	03/04/2009	Swap	01/11 - 03/11	5,000	$57.00
NYMEX	04/08/2009	Swap	04/11 - 06/11	5,000	$68.80
NYMEX	04/23/2009	Swap	04/11 - 06/11	5,000	$65.10
NYMEX	06/02/2009	Swap	10/10 - 12/10	5,000	$74.30
NYMEX	06/02/2009	Swap	01/11 - 03/11	5,000	$75.05
NYMEX	06/02/2009	Swap	04/11 - 06/11	5,000	$75.86
NYMEX	06/04/2009	Put	04/11 - 06/11	5,000	$67.00
NYMEX	09/02/2009	Swap	07/11 - 09/11	5,000	$75.10
NYMEX	09/02/2009	Put	07/11 - 09/11	5,000	$63.00
NYMEX	09/29/2009	Swap	07/11 - 09/11	5,000	$74.00
NYMEX	10/06/2009	Put	07/11 - 09/11	5,000	$65.00
NYMEX	10/09/2009	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	01/08/2010	Swap	04/10 - 06/10	5,000	$84.30
NYMEX	01/08/2010	Swap	07/10 - 09/10	5,000	$85.60
NYMEX	01/08/2010	Swap	10/10 - 12/10	5,000	$86.88
NYMEX	01/08/2010	Put	10/11 - 12/11	6,000	$75.00
NYMEX	01/08/2010	Put	01/12 - 03/12	5,000	$75.00
NYMEX	01/25/2010	Swap	01/12 - 03/12	5,000	$83.30

NYMEX	02/26/2010	Swap	01/12 - 03/12	5,000	$83.80
NYMEX	03/19/2010	Swap	01/12 - 03/12	5,000	$83.80
NYMEX	03/19/2010	Swap	04/12 - 06/12	5,000	$84.00
NYMEX	03/31/2010	Put	04/12 - 06/12	5,000	$75.00

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, 2010. 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, 2010 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 2009 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

Item 1A. Risk Factors

Except to the extent updated or described below, our Risk Factors are documented in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2009.

Municipal governments within our utility service territories possess the power of condemnation, and could seek a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations, and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. Although condemnation is a process that is subject to constitutional protections requiring just compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

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 or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2010 -January 31, 2010	13,513	$ 26.59	-	-
February 1, 2010 - February 28, 2010	1,252	$ 26.58	-	-
March 1, 2010 - March 31, 2010	-	$ -	-	-
Total	14,765	$ 26.59	-	-

(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.

80

Item 6. Exhibits

Exhibit 10.1	Amended and Restated Form of Short-Term Incentive for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2010.
Exhibit 10.2	Credit Agreement dated April 15, 2010 among Black Hills Corporation, as Borrower, The Royal Bank of Scotland Plc., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Company's Form 8-K filed on April 21, 2010 and incorporated by reference herein).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
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.

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 7, 2010

EXHIBIT INDEX

Exhibit Number	Description
Exhibit 10.1	Amended and Restated Form of Short-Term Incentive for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2010.
Exhibit 10.2	Credit Agreement dated April 15, 2010 among Black Hills Corporation, as Borrower, The Royal Bank of Scotland Plc., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Company's Form 8-K filed on April 21, 2010 and incorporated by reference herein).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
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.