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

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GLOSSARY OF TERMS AND ABBREVIATIONS AND ACCOUNTING STANDARDS

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

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

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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.

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(4) MATERIALS, SUPPLIES AND FUEL

The amounts of materials, supplies and fuel included on the accompanying Condensed Consolidated Balance Sheets, by major classification, 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

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(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

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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

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