BLACK HILLS CORP /SD/
Form 10-Q
August 06, 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 June 30, 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 x No o

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

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

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

Yes o	No x

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

Class	Outstanding at July 30, 2010
Common stock, $1.00 par value	39,204,087 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
Annexation Agreement	Agreement with the City of Pueblo, Colorado under which the City of Pueblo annexed the property on which Colorado Electric and Colorado IPP are constructing their generation facilities
AOCI	Accumulated Other Comprehensive Income (Loss)
Aquila	Aquila, Inc.
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
Blackbox	Blackbox settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are confidential
Black Hills Electric Generation	Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company that was formerly known as Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Service Company	Black Hills Service Company, a direct wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit

CFTC	Commodities Futures and Trading Commission
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado IPP	Black Hills Colorado IPP, a direct wholly-owned subsidiary of Black Hills Electric Generation
Corporate Credit Facility	Our $525 million credit facility which was terminated on April 15, 2010
CPUC	Colorado Public Utilities Commission
De-designated interest rate swaps	The $250.0 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but were de-designated in December 2008

DOE	U.S. Department of Energy
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
EDF	EDF Trading North America, LLC
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 Producer
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
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers 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
Participation Agreement	Amended and Restated Wygen III Participation Agreement dated July 14, 2010 between BHP, MDU and JPB, which includes JPB as partial owner of Wygen III
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement

PPACA	Patient Protection and Affordability Care Act
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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands, except per share amounts)			
Operating revenues	$ 271,291	$ 257,349	$ 713,623	$ 695,292
Operating expenses:				
Fuel and purchased power	113,152	112,169	365,687	373,189
Operations and maintenance	39,520	40,461	82,142	79,795
Gain on sale of operating assets	—	—	(2,683)	(25,971)
Administrative and general	46,404	37,708	85,492	79,474
Depreciation, depletion and amortization	30,260	29,386	58,655	62,712
Taxes, other than income taxes	11,120	11,811	23,793	23,509
Impairment of long-lived assets	—	—	—	43,301
Total operating expenses	240,456	231,535	613,086	636,009
Operating income	30,835	25,814	100,537	59,283
Other income (expense):				
Interest expense	(22,622)	(23,338)	(44,388)	(42,239)
Interest rate swap - unrealized (loss) gain	(24,918)	31,706	(27,953)	46,469
Interest income	84	329	330	856
Allowance for funds used during construction - equity	260	1,314	2,288	2,686
Other income, net	1,268	893	1,686	1,637
Total other income (expenses)	(45,928)	10,904	(68,037)	9,409
(Loss) income from continuing operations before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	(15,093)	36,718	32,500	68,692
Equity in earnings (loss) of unconsolidated subsidiaries	1,291	1,576	1,608	1,249
Income tax benefit (expense)	5,143	(13,713)	(11,333)	(19,735)

(Loss) income from continuing operations	(8,659)	24,581	22,775	50,206
Income from discontinued operations, net of taxes	—	—	—	766
Net (loss) income	$ (8,659)	$ 24,581	$ 22,775	$ 50,972
Weighted average common shares outstanding:				
Basic	38,902	38,598	38,875	38,554
Diluted	38,902	38,658	39,042	38,611
Earnings (loss) per share:				
Basic-				
Continuing operations	$ (0.22)	$ 0.64	$ 0.59	$ 1.30
Discontinued operations	—	—	—	0.02
Total (loss) earnings per share - basic	$ (0.22)	$ 0.64	$ 0.59	$ 1.32
Diluted-				
Continuing operations	$ (0.22)	$ 0.64	$ 0.58	$ 1.30
Discontinued operations	—	—	—	0.02
Total (loss) earnings per share - diluted	$ (0.22)	$ 0.64	$ 0.58	$ 1.32
Dividends paid per share of common stock	$ 0.360	$ 0.355	$ 0.720	$ 0.710

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)

	June 30, 2010	December 31, 2009	June 30, 2009
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 64,033	$ 112,901	$ 122,351
Restricted cash	16,169	17,502	—
Accounts receivables, net	208,185	274,489	181,250
Materials, supplies and fuel	135,049	123,322	88,672
Derivative assets, current	54,589	37,747	75,600
Income tax receivable, net	—	2,031	—
Deferred income tax asset, current	19,956	4,523	17,640
Regulatory assets, current	41,852	25,085	14,086
Other current assets	13,339	27,270	31,917
Total current assets	553,172	624,870	531,516
Investments	18,261	18,524	20,316
Property, plant and equipment	3,141,029	2,975,993	2,819,510
Less accumulated depreciation and depletion	(852,414)	(815,263)	(773,278)
Total property, plant and equipment, net	2,288,615	2,160,730	2,046,232
Other assets:			
Goodwill	353,734	353,734	359,288
Intangible assets, net	4,189	4,309	4,784
Derivative assets, non-current	9,726	3,777	5,029
Regulatory assets, non-current	121,026	135,578	133,386
Other assets, non-current	21,559	16,176	11,189
Total other assets	510,234	513,574	513,676
TOTAL ASSETS	$ 3,370,282	$ 3,317,698	$ 3,111,740

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

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

	June 30, 2010	December 31, 2009	June 30, 2009
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 206,422	$ 229,352	$ 175,190
Accrued liabilities	130,194	151,504	133,291
Derivative liabilities, current	91,259	57,166	69,347
Accrued income taxes, net	13,974	—	27,152
Regulatory liabilities, current	22,447	7,092	36,943
Notes payable	225,000	164,500	270,500
Current maturities of long-term debt	4,539	35,245	32,086
Total current liabilities	693,835	644,859	744,509
Long-term debt, net of current maturities	990,130	1,015,912	719,243
Deferred credits and other liabilities:			
Deferred income tax liability, non-current	271,684	262,034	233,592
Derivative liabilities, non-current	18,177	11,999	12,098
Regulatory liabilities, non-current	50,227	42,458	39,967
Benefit plan liabilities	148,190	140,671	160,712
Other deferred credits and other liabilities	115,656	114,928	121,519
Total deferred credits and other liabilities	603,934	572,090	567,888
Stockholders' equity:			
Common stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; Issued 39,204,231; 38,977,526 and 38,836,918 shares, respectively	39,204	38,978	38,837
Additional paid-in capital	595,219	591,390	586,879
Retained earnings	468,430	473,857	470,883
Treasury stock at cost – 1,021; 8,834 and 3,549 shares, respectively	(27)	(224)	(84)
Accumulated other comprehensive loss	(20,443)	(19,164)	(16,415)
Total stockholders' equity	1,082,383	1,084,837	1,080,100
	$ 3,370,282	$ 3,317,698	$ 3,111,740

TOTAL LIABILITIES AND STOCKHOLDERS'
EQUITY

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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Six Months Ended June 30,	
	2010	2009
Operating activities:	(in thousands)	
Net income	$ 22,775	$ 50,972
Income from discontinued operations, net of taxes	—	(766)
Income from continuing operations	22,775	50,206
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	58,655	62,712
Impairment of long-lived assets	—	43,301
Derivative fair value adjustments	(2,445)	12,780
Gain on sale of operating assets	(2,683)	(25,971)
Stock compensation	1,971	744
Unrealized mark-to-market loss (gain) on interest rate swaps	27,953	(46,469)
Deferred income taxes	(6,078)	(21)
Equity in (earnings) loss of unconsolidated subsidiaries	(1,608)	(1,249)
Allowance for funds used during construction - equity	(2,288)	(2,686)
Employee benefit plans	8,143	8,556
Other non-cash adjustments	3,380	2,333
Change in operating assets and liabilities:		
Materials, supplies and fuel	(19,896)	31,938
Accounts receivable and other current assets	93,873	164,718
Accounts payable and other current liabilities	(50,011)	(112,073)
Regulatory assets	(2,806)	31,623
Regulatory liabilities	13,401	30,939
Other operating activities	1,654	(6,024)
Net cash provided by operating activities of continuing operations	143,990	245,357
Net cash provided by operating activities of discontinued operations	—	883
Net cash provided by operating activities	143,990	246,240
Investing activities:		
Property, plant and equipment additions	(171,115)	(163,608)
Proceeds from sale of ownership interest in operating assets	6,105	84,199
Payment for acquisition of business	(2,250)	—
Working capital adjustment of purchase price allocation on Aquila assets	—	7,658

Other investing activities	4,239	(4,963)
Net cash used in investing activities	(163,021)	(76,714)
Financing activities:		
Dividends paid	(28,202)	(27,542)
Common stock issued	2,281	1,553
Increase in short-term borrowings	268,500	272,500
Decrease in short-term borrowings	(208,000)	(705,800)
Long-term debt - issuances	—	248,500
Long-term debt - repayments	(56,488)	(2,001)
Other financing activities	(7,928)	(2,917)
Net cash used in financing activities	(29,837)	(215,707)
Decrease in cash and cash equivalents	(48,868)	(46,181)
Cash and cash equivalents:		
Beginning of period	112,901	168,532
End of period	$ 64,033	$ 122,351

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 estimates which are, in the opinion of management, necessary for a fair presentation of the June 30, 2010, December 31, 2009 and June 30, 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 and six months ended June 30, 2010 and June 30, 2009, and our financial condition as of June 30, 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 AND LEGISLATION

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 ongoing re-evaluation. The adoption of this standard in January 2010 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. The additional disclosures are included in Note 14 of the accompanying Notes to Condensed Consolidated Financial Statements.

Recently Issued Accounting Standards and Legislation

Patient Protection and Affordable Care Act (HR 3590 and HR 4872)

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

Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173)

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

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six Months Ended

	June 30, 2010	June 30, 2009
	(in thousands)	
Non-cash investing activities—		
Property, plant and equipment acquired with accrued liabilities	$ 32,207	$ 40,053
Cash (paid) refunded during the period for—		
Interest (net of amounts capitalized)	$ (26,881)	$ (41,969)
Income taxes	$ (399)	$ 23,861

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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	June 30, 2010	December 31, 2009	June 30, 2009
Materials and supplies	$ 32,361	$ 31,535	$ 32,145
Fuel - Electric Utilities	8,913	7,128	7,264
Natural gas in storage — Gas Utilities	15,513	24,053	13,109
Gas and oil held by Energy Marketing*	78,262	60,606	36,154
Total materials, supplies and fuel	$ 135,049	$ 123,322	$ 88,672

* As of June 30, 2010, December 31, 2009 and June 30, 2009, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(8.5) million, $(0.3) million and $(3.8) 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. Natural gas volumes held as of June 30, 2010, December 31, 2009 and June 30, 2009 include 16,289,903 MMBtu, 12,152,465 MMBtu, and 9,437,198 MMBtu, respectively. Crude oil volumes held as of June 30, 2010, December 31, 2009 and June 30, 2009 include 118,000 Bbl, 69,045 Bbl, and 62,000 Bbl, respectively.

Natural gas in storage at our Gas Utilities represents primarily gas purchased for use by our customers. Natural gas volumes held in storage by us fluctuates with the seasonality of our business and the commodity price of natural gas, and the carrying values are impacted by price fluctuations. Volumes held as of June 30, 2010, December 31, 2009 and June 30, 2009 include 3,730,489 MMBtu, 6,866,550 MMBtu and 3,563,638 MMBtu, respectively.

(5) ACCOUNTS RECEIVABLE AND 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 our ability to collect.

Following is a summary of receivables (in thousands):

	June 30, 2010	December 31, 2009	June 30, 2009
Accounts receivable, trade	$ 185,746	$ 217,723	$ 161,261
Unbilled revenues	26,736	61,387	26,999
Total accounts receivable	212,482	279,110	188,260
Less allowance for doubtful accounts	(4,297)	(4,621)	(7,010)
Accounts receivable, net	$ 208,185	$ 274,489	$ 181,250

(6) NOTES PAYABLE

Our credit facilities and debt securities contain certain restrictive covenants including, among others, recourse leverage ratios and consolidated net worth covenant. At June 30, 2010, except as noted below for the Enserco Credit Facility, we were in compliance with these covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

Revolving Credit Facility

On April 15, 2010, we terminated our $525 million Corporate Credit Facility and entered into a new $500 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. The covenants and events of default are substantially the same as the prior facility, except the minimum interest expense coverage ratio covenant was eliminated. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively. The new facility contains a commitment fee to be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.5%. The facility contains an accordion feature which allows us to increase the capacity of the facility to $600 million. Deferred financing costs of $4.6 million were capitalized and are being amortized over the three-year term of the facility. Amortization of deferred financing costs was $0.4 million and $0.4 million for the three and six months ended June 30, 2010, respectively, and $0.1 million and $0.3 million for the three and six months ended June 30, 2009, respectively.

Our consolidated net worth was $1,082.4 million at June 30, 2010, which was approximately $246.1 million in excess of the net worth we are required to maintain under the Revolving Credit Facility. At June 30, 2010, our long-term debt ratio was 47.8%, our total debt leverage ratio (long-term debt and short-term debt) was 53.0%, and our recourse leverage ratio was 54.6%. We are currently in compliance with these covenants.

Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year $250 million committed credit facility. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility to $350 million. This facility replaces the $300 million credit facility which expired on May 7, 2010. Maximum borrowings under the facility are subject to a sub-limit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%.

At June 30, 2010, $141.4 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding. Deferred financing costs of $2.1 million were recorded for the Enserco Credit Facility and are being amortized over the term of the Facility. Amortization of deferred financing costs under our committed Enserco Credit Facility is included in Interest expense on the accompanying Condensed Consolidated Income Statement. Amortization of deferred financing costs was approximately $0.4 million and $1.0 million for the three and six months ended June 30, 2010, respectively, and $0.3 million and $0.4 million for the three and six months ended June 30, 2009, respectively.

The June 1, 2010 coal marketing acquisition (see Note 20) included certain contractual positions that caused Enserco to temporarily not in compliance with one of the non-financial covenants to the Enserco Credit Facility as of June 30, 2010. The Enserco Credit Facility limited the net fixed price volume of coal to 1.0 million tons. As of June 30, 2010, Enserco was above that limit. In July, the participating banks waived the non-compliance with this covenant and increased the permitted net fixed price volume of coal allowed to 2.25 million tons for July 2010 and 2.0 million tons thereafter.

(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 of principal 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 included the principal balance of $2.5 million plus accrued interest and an early redemption premium of 2.618%. 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. A total of $21.8 million was paid on June 1, 2010, which included the principal balance of $20.0 million plus accrued interest and an early redemption premium of 4.675%. 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.

(8) EARNINGS PER SHARE

Basic earnings per share from continuing operations are 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, used to compute earnings per share, is as follows (in thousands):

Period ended June 30, 2010	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
(Loss) income from continuing operations	$ (8,659)		$ 22,775	
Basic earnings	$ (8,659)	38,902	$ 22,775	38,875
Dilutive effect of:				
Restricted stock	—	—	—	99
Other	—	—	—	68
Diluted (loss) earnings	$ (8,659)	38,902	$ 22,775	39,042
Diluted (loss) earnings per share	$ (0.22)		$ 0.58	

Period ended June 30, 2009	Three Months		Six Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 24,581		$ 50,206	

Basic earnings	$ 24,581	38,598	$ 50,206	38,554
Dilutive effect of:				
Restricted stock	—	60	—	57
Diluted earnings	$ 24,581	38,658	$ 50,206	38,611
Diluted earnings per share	$ 0.64		$ 1.30	

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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Options to purchase common stock	137	435	228	435
Restricted stock	108	—	—	—
Other	64	—	—	—
	309	435	228	435

(9) OTHER COMPREHENSIVE (LOSS) INCOME

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

	Three Months Ended June 30,	
	2010	2009
Net (loss) income	$ (8,659)	$ 24,581
Other comprehensive (loss) income, net of tax:		
Minimum pension liability adjustments (net of tax of $(—))	(27)	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $746 and $4,072, respectively)	(1,283)	(7,793)
Reclassification adjustments on cash flow hedges settled and included in net (loss) income (net of tax of $1,843 and $(2,143), respectively)	(3,274)	3,793
Comprehensive (loss) income	$ (13,243)	$ 20,581

	Six Months Ended June 30,	
	2010	2009
Net income	$ 22,775	$ 50,972
Other comprehensive income, net of tax:		
Minimum pension liability adjustments (net of tax of $(7))	(15)	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $155 and $2,928, respectively)	133	(4,795)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $782 and $(4,060), respectively)	(1,397)	7,163
Comprehensive income	$ 21,496	$ 53,340

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

	June 30, 2010	December 31, 2009	June 30, 2009
Derivatives designated as cash flow hedges	$ (10,751)	$ (9,462)	$ (2,191)
Employee benefit plans	(9,651)	(9,636)	(14,127)
Amount from equity-method investees	(41)	(66)	(97)
Total	$ (20,443)	$ (19,164)	$ (16,415)

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(10) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the first six 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 six months ended June 30, 2010. Pre-tax compensation cost related to the awards was approximately $0.3 million, which was accrued for in 2009.

- We granted 159,230 restricted common shares during the six months ended June 30, 2010. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $4.2 million will be recognized over the three-year vesting period.

- 30,000 stock options were exercised during the six months ended June 30, 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 June 30, 2010 and 2009 was $1.1 million and $1.4 million, respectively, and for the six months ended June 30, 2010 and 2009 was $2.9 million and $1.8 million, respectively.

As of June 30, 2010, total unrecognized compensation expense related to non-vested stock awards was $8.8 million and is expected to be recognized over a weighted-average period of 2.1 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 57,235 new shares at a weighted-average price of $28.36 during the six months ended June 30, 2010. At June 30, 2010, 238,747 shares of unissued common stock were available for future offering under the Plan.

Dividend Restrictions

Our Revolving Credit Facility contains restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: a recourse leverage ratio not to exceed 0.65 to 1.00 and a minimum consolidated net worth of $625 million plus 50% of aggregate consolidated net income since January 1, 2005. As of June 30, 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 June 30, 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 be subject to further restrictions under the Federal Power Act. As of June 30, 2010, the restricted net assets at our Utilities Group were approximately $164.0 million.

- Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, Enserco may be restricted from making dividend payments to its parent company. Enserco's restricted net assets at June 30, 2010 were $78.7 million.

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

(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 June 30,		Six Months Ended June 30,	
2010	2009	2010	2009
$ 1,533	$ 1,929	$ 3,066	$ 3,858

Service cost				
Interest cost	3,773	3,679	7,546	7,358
Expected return on plan assets	(3,623)	(3,458)	(7,246)	(6,916)
Prior service cost	305	41	610	82
Net loss	500	752	1,000	1,504
Net periodic benefit cost	$ 2,488	$ 2,943	$ 4,976	$ 5,886

We made contributions of less than $0.1 million to the Plans in the first six months of 2010. Contributions of less than $0.1 million and $30.1 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Service cost	$ 377	$ 260	$ 754	$ 520
Interest cost	611	542	1,222	1,084
Expected return on plan assets	(52)	(56)	(104)	(112)
Prior service benefit	(77)	(22)	(154)	(44)
Net transition obligation	—	15	—	30
Net loss (gain)	159	(8)	318	(16)
Net periodic benefit cost	$ 1,018	$ 731	$ 2,036	$ 1,462

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 each of the three and six month periods ended June 30, 2010 and 2009, respectively.

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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Service cost	$ 171	$ 117	$ 342	$ 234
Interest cost	321	344	642	688
Prior service cost	1	1	2	2
Net loss	71	147	142	294
Net periodic benefit cost	$ 564	$ 609	$ 1,128	$ 1,218

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 June 30, 2010, substantially all of our operations and assets were located within the United States.

We conduct our operations through the following six reportable segments:

Utilities Group —

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

- Gas Utilities, which supplies natural gas utility service 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, coal and related services primarily in the United States and Canada.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 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 June 30, 2010	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$ 135,496	$ 769	$ 7,196
Gas	87,115	—	(886)
Non-regulated Energy:			
Oil and Gas	18,658	—	221
Power Generation	6,679	—	(416)
Coal Mining	7,805	7,244	3,074
Energy Marketing	8,895	—	1,327
Corporate [(a)]	—	—	(19,161)
Inter-segment eliminations	—	(1,370)	(14)
Total	$ 264,648	$ 6,643	$ (8,659)

Three Months Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$ 118,606	$ 215	$ 4,541
Gas	93,338	—	442
Non-regulated Energy:			
Oil and Gas	17,829	—	129
Power Generation	7,215	—	758
Coal Mining	7,746	5,747	(499)
Energy Marketing	7,738	—	2,210
Corporate [(a)]	—	—	16,780
Inter-segment eliminations	—	(1,085)	220
Total	$ 252,472	$ 4,877	$ 24,581

	External	Inter-segment	Income (Loss)

Six Months Ended June 30, 2010	Operating Revenues	Operating Revenues	from Continuing Operations
Utilities:			
Electric	$ 284,132	$ 942	$ 17,048
Gas (b)	330,285	—	18,612
Non-regulated Energy:			
Oil and Gas	38,401	—	2,569
Power Generation	14,747	—	664
Coal Mining	14,687	14,342	4,420
Energy Marketing	18,667	—	3,520
Corporate (a)	—	—	(24,128)
Inter-segment eliminations	—	(2,580)	70
Total	$ 700,919	$ 12,704	$ 22,775

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Six Months Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$ 255,665	$ 430	$ 13,858
Gas	349,676	—	17,708
Non-regulated Energy:			
Oil and Gas (c)	34,340	—	(25,591)
Power Generation (d)	14,834	—	17,911
Coal Mining	15,683	12,212	319
Energy Marketing	14,557	—	3,247
Corporate (a)	—	—	22,316
Inter-segment eliminations	—	(2,105)	438
Total	$ 684,755	$ 10,537	$ 50,206

(a) Income (loss) from continuing operations includes $16.2 million and $18.2 million net after-tax mark-to-market loss on interest rate swaps for the three and six months ended June 30, 2010 and a $20.6 million and $30.2 million net after-tax mark-to-market gain on interest rate swaps for the three and six months ended June 30, 2009.

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

(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.

Total assets	June 30, 2010	December 31, 2009	June 30, 2009
Utilities:			
Electric	$ 1,736,413	$ 1,659,375	$ 1,558,525
Gas	622,585	684,375	628,152
Non-regulated Energy:			
Oil and Gas	348,509	338,470	347,198
	197,545	161,856	119,876

Power Generation			
Coal Mining	87,474	76,209	75,647
Energy Marketing	294,043	321,207	299,374
Corporate	83,713	76,206	82,968
Total	$ 3,370,282	$ 3,317,698	$ 3,111,740

(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, natural gas and coal 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, Crude Oil and Coal Marketing

We have a natural gas, crude oil and coal 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, crude oil and coal 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, crude oil and coal 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, crude oil and coal marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting for derivatives and hedging generally does not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas, crude oil and coal marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions results from these accounting requirements.

To effectively manage our portfolios, we enter into forward physical commodity contracts, financial derivative instruments including over-the-counter swaps and options, and storage and transportation agreements. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed in the BHCRPP and further delineated in the Risk Management Policies and Procedures as approved by our Executive Risk Committee. Our trading contracts do not include credit risk-related contingent features that require us to maintain a specific credit rating.

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

	Outstanding at June 30, 2010		Outstanding at December 31, 2009		Outstanding at June 30, 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	238,853	21	231,703	22	289,140	28
Natural gas basis swaps sold	252,060	21	232,673	22	302,324	28
Natural gas fixed-for-float swaps purchased	67,103	39	60,927	16	90,974	21
Natural gas fixed-for-float swaps sold	86,200	19	72,904	25	100,088	18
Natural gas physical purchases	122,687	21	120,680	27	168,381	18
Natural gas physical sales	123,629	39	124,830	27	184,873	21

	Outstanding at June 30, 2010		Outstanding at December 31, 2009		Outstanding at June 30, 2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	4,673	6	5,048	12	5,595	6

Crude oil physical sales	4,754	6	4,998	12	4,925	6
Crude oil swaps/options purchased	—	—	—	—	42	3
Crude oil swaps/options sold	140	4	69	2	111	3

	Outstanding at June 30, 2010 *	
	Notional Amounts	Latest Expiration (months)
(in thousands of tons)		
Coal fixed-for-float swaps purchased	6,910	29
Coal fixed-for-float swaps sold	4,985	30
Coal physical purchases	24,925	54
Coal physical sales	6,472	38
Coal options purchased	334	42
Coal options sold	1,804	30

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* Coal contracts represent the contractual positions of the coal marketing business acquired on June 1, 2010 and contracts arising from subsequent trading activity.

Derivatives and certain natural gas, crude oil and coal marketing activities were marked to fair value on June 30, 2010, December 31, 2009 and June 30, 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):

	June 30, 2010	December 31, 2009	June 30, 2009
Derivative assets, current	$ 41,576	$ 25,366	$ 52,870
Derivative assets, non-current	$ 5,888	$ 3,090	$ 1,802
Derivative liabilities, current	$ 15,912	$ 9,377	$ 14,970
Derivative liabilities, non-current	$ (168)	$ (733)	$ (1,917)
Cash collateral (receivable)/payable included in derivative assets/liabilities	$ —	$ (2,728)	$ (9,267)
Unrealized gain	$ 31,720	$ 17,084	$ 32,352

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 June 30, 2010, December 31, 2009 and June 30, 2009, the market adjustments recorded in inventory were $(8.5) million, $(0.3) million and $(3.8) 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 June 30, 2010, December 31, 2009 and June 30, 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, documented under accounting for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

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

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

	June 30, 2010		December 31, 2009		June 30, 2009	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional*	520,500	9,397,800	472,500	9,602,300	480,000	9,862,050
Maximum terms in years **	0.25	0.5	0.25	0.75	0.25	0.75
Derivative assets, current	$ 2,040	$ 6,855	$ 3,345	$ 5,994	$ 3,600	$ 14,012
Derivative assets, non-current	$ 855	$ 2,983	$ 136	$ 551	$ 1,453	$ 1,612
Derivative liabilities, current	$ 2,170	$ 44	$ 1,220	$ 1,435	$ —	$ 361
Derivative liabilities, non-current	$ 178	$ 4	$ 2,502	$ 391	$ 1,995	$ 1,392
Pre-tax accumulated other comprehensive income (loss) included in balance sheets	$ (161)	$ 9,790	$ (862)	$ 4,719	$ 2,543	$ 13,871
Earnings	$ 708	$ —	$ 621	$ —	$ 515	$ —

* 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 June 30, 2010 market prices, a $5.5 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 June 30, 2010		Outstanding at December 31, 2009		Outstanding at June 30, 2009	
Notional Amounts*	Latest Expiration	Notional Amounts*	Latest Expiration	Notional Amounts *	Latest Expiration

		(months)		(months)		(months)
Natural gas futures purchased	8,230,000	21	6,220,000	15	8,920,000	21
Natural gas options purchased	1,520,000	9	1,910,000	3	2,650,000	9
Natural gas basis swaps purchased	—	—	225,000	3	377,500	9

* Gas in MMBtus

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

	June 30, 2010	December 31, 2009	June 30, 2009
Derivative assets, current [(a)]	$ 3,806	$ 3,042	$ 5,118
Derivative assets, non-current	$ —	$ —	$ 162
Derivative liabilities, non-current	$ 612	$ 764	$ 159
Net unrealized loss included in regulatory assets	$ 7,150	$ 2,578	$ 2,163
Cash collateral receivable (payable) included in derivative assets/liabilities	$ 9,551	$ 3,789	$ 5,792

(a) Includes option premium of $0.8 million, $1.1 million and $1.5 million at June 30, 2010, December 31, 2009 and June 30, 2009, respectively, which will be recorded as a regulatory asset upon settlement of the options.

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 assets, current and 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 margin upon settlement.

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

	June 30, 2010	December 31, 2009
Notional *	232,500	232,500
Maximum terms in months	4	10
Current derivative asset	$ 312	$ —
Current derivative liability	$ —	$ 5
Pre-tax accumulated other comprehensive income (loss) included in the Condensed Consolidated Balance Sheets	$ 312	$ (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.

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

	June 30, 2010		December 31, 2009		June 30, 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	6.50	0.50	7.00	1.00	7.50	0.50
Derivative liabilities, current	$ 6,393	$ 66,740	$ 6,342	$ 38,787	$ 6,045	$ 47,971
Derivative liabilities, non-current	$ 17,551	$ —	$ 9,075	$ —	$ 10,469	$ —
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$ (23,944)	$ —	$ (15,417)	$ —	$ (16,514)	$ —
Pre-tax (loss) gain included in Condensed Consolidated Income Statements	$ —	$ (27,953)	$ —	$ 55,653	$ —	$ 46,469

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

Based on June 30, 2010 market interest rates and balances related to our $150 million in designated interest rate swaps, a loss of approximately $6.4 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 rate risk for us. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollar.

The outstanding forward exchange contracts, which had a fair value of less than $0.1 million at June 30, 2010 and June 30, 2009, respectively, were recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. For the three and six months ended June 30, 2010, the unrealized foreign exchange (loss) gain was less than $(0.1) million and $0.1 million, respectively, while for the three and six months ended June 30, 2009, the amount of unrealized foreign exchange loss was $(0.3) million and less than $(0.1) million, respectively. For the three and six months ended June 30, 2010, the realized foreign currency exchange loss was $(0.5) million and $(0.6) million, respectively, while for the three and six months ended June 30, 2009, the amount of foreign currency exchange gain was $1.4 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.

Recurring Fair Value Measures

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010, December 31, 2009 and June 30, 2009 (in thousands):

	At Fair Value as of June 30, 2010				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives — Energy Marketing	$ —	$ 173,008	$ 3,411	$ (128,909)	$ 47,510
Commodity derivatives — Oil and Gas	—	11,422	1,265	—	12,687
Commodity derivatives — Regulated Utilities Group	—	(5,433)	—	9,551	4,118
Money market funds	9,006	—	—	—	9,006
Total	$ 9,006	$ 178,997	$ 4,676	$ (119,358)	$ 73,321
Liabilities:					
Commodity derivatives — Energy Marketing	$ —	$ 142,184	$ 2,500	$ (128,908)	$ 15,776
Commodity derivatives — Oil and Gas	—	2,349	—	—	2,349
Commodity derivatives — Regulated Utilities Group	—	612	—	—	612
Foreign currency derivative	—	15	—	—	15
Interest rate swaps	—	90,684	—	—	90,684
Total	$ —	$ 235,844	$ 2,500	$ (128,908)	$ 109,436

	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

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	At Fair Value as of June 30, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral[(a)]	Total
Assets:					
Commodity derivatives	$ —	$ 252,368	$ 13,189	$ (184,929)	$ 80,628
Liabilities:					
Commodity derivatives	$ —	$ 208,577	$ 8,036	$ (199,987)	$ 16,626
Foreign currency derivatives	—	334	—	—	334
Interest rate swaps	—	64,486	—	—	64,486
Total	$ —	$ 273,397	$ 8,036	$ (199,987)	$ 81,446

(a) Cash Collateral on deposit in margin accounts under master netting agreements at June 30, 2010, December 31, 2009 and June 30, 2009 totaled a net $9.6 million, $6.5 million and $15.1 million, respectively.

The following tables present the changes in level 3 recurring fair value for the three and six months ended June 30, 2010 and 2009, respectively (in thousands):

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
	Commodity Derivatives	Commodity Derivatives
Balance as of beginning of period	$ 1,295	$ (556)
Unrealized losses	(952)	(2,167)
Unrealized gains	2,345	3,726
Purchases, issuance and settlements	(498)	(805)
Transfers into level 3 [(a)]	(16)	(16)
Transfers out of level 3[(b)]	2	1,994
Balances at end of period	$ 2,176	$ 2,176
Changes in unrealized gains relating to instruments still held as of quarter-end	$ 66	$ 1,811

	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
	Commodity Derivatives	Commodity Derivatives

Balance as of beginning of period	$ 13,407	$ 16,398
Realized and unrealized losses	(1,310)	(1,555)
Purchases, issuance and settlements	(747)	(6,054)
Transfers in and/or out of level 3 [(a)] [(b)]	(6,197)	(3,636)
Balances at end of period	$ 5,153	$ 5,153
Changes in unrealized losses relating to instruments still held as of quarter-end	$ (7,013)	$ (10,455)

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

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

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income. If an investor seeks to conduct an analysis of commodity derivatives classified as level 3, the analysis should 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.

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions. Further, the amounts do not include net cash collateral of $9.6 million, $6.5 million and $15.1 million on deposit in margin accounts at June 30, 2010, December 31, 2009, and June 30, 2009, respectively, 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 tables present the fair value and balance sheet classification of our derivative instruments as of June 30, 2010 and 2009 (in thousands):

Fair Value as of June 30, 2010

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 9,790	$ 1,369
Commodity derivatives	Derivative assets — non-current	6	—
Commodity derivatives	Derivative liabilities — current	16	8
Commodity derivatives	Derivative liabilities — non-current	—	8
Interest rate swaps	Derivative liabilities — current	—	6,393
Interest rate swaps	Derivative liabilities — non-current	—	17,551
Total derivatives designated as hedges		$ 9,812	$ 25,329
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 151,994	$ 115,377
Commodity derivatives	Derivative assets — non-current	20,657	10,937
Commodity derivatives	Derivative liabilities — current	13,891	32,010
Commodity derivatives	Derivative liabilities — non-current	—	618
Foreign currency derivatives	Derivative liabilities — current	—	15
Interest rate swap	Derivative liabilities — current	—	66,740
		$ 186,542	$ 225,697

Total derivatives not designated as hedges

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Fair Value as of December 31, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 4,163	$ 2,977
Commodity derivatives	Derivative assets — non-current	72	—
Commodity derivatives	Derivative liabilities — current	16	801
Commodity derivatives	Derivative liabilities — non-current	—	55
Interest rate swaps	Derivative liabilities — current	—	6,342
Interest rate swaps	Derivative liabilities — non-current	—	9,075
Total derivatives designated as hedges		$ 4,251	$ 19,250
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 135,807	$ 103,035
Commodity derivatives	Derivative assets — non-current	6,490	2,785
Commodity derivatives	Derivative liabilities — current	19,089	33,069
Commodity derivatives	Derivative liabilities — non-current	946	3,815
Interest rate swap	Derivative liabilities — current	—	38,787
Total derivatives not designated as hedges		$ 162,332	$ 181,491

Fair Value as of June 30, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 7,500	$ 3,444
Commodity derivatives	Derivative assets — non-current	3	—
Commodity derivatives	Derivative liabilities — current	55	363
Commodity derivatives	Derivative liabilities — non-current	—	5
Interest rate swaps	Derivative liabilities — current	—	6,045
Interest rate swaps	Derivative liabilities — non-current	—	10,469
Total derivatives designated as hedges		$ 7,558	$ 20,326
Derivatives designated as hedges:			

Commodity derivatives	Derivative assets — current	$ 243,199	$ 186,714
Commodity derivatives	Derivative assets — non-current	15,875	10,849
Commodity derivatives	Derivative liabilities — current	12,776	27,465
Commodity derivatives	Derivative liabilities — non-current	79	1,703
Interest rate swap	Derivative liabilities — current	—	47,971
Foreign currency derivatives	Derivative liabilities — current	—	334
Total derivatives designated as hedges		$ 271,929	$ 275,036

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 and six months ended June 30, 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 and six months ended June 30, 2010 and June 30, 2009 are presented as follows (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
for the Three and Six Months Ended June 30, 2010

Fair Value Hedges

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ (3,199)	$ 8,009
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	2,569	(8,178)
		$ (630)	$ (169)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
for the Three and Six Months Ended June 30, 2009

Fair Value Hedges

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended June 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ (639)	$ 6,881

Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	1,415	(5,540)
		$ 776	$ 1,341

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income for the three and six months ended June 30, 2010 and June 30, 2009 are 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 June 30, 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	$ (9,812)	Interest expense	$ (3,519)		$ —
Commodity derivatives	(491)	Operating revenue	(5,191)	Operating revenue	(154)
Total	$ (10,303)		$ (8,710)		$ (154)

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The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and the Balance Sheet for the Three Months Ended June 30, 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 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	$ 9,606	Interest expense	$ (610)		$ —
Commodity derivatives	(15,663)	Operating revenue	6,546	Operating revenue	(167)
Total	$ (6,057)		$ 5,936		$ (167)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and the Balance Sheet for the Six Months Ended June 30, 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 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	$ (11,886)	Interest expense	(3,824)		$ —
Commodity derivatives	6,090	Operating revenue	(1,948)	Operating revenue	(317)
Total	$ (5,796)		$ (5,772)		$ (317)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income and the Balance Sheet for the Six Months Ended June 30, 2009

Cash Flow Hedges

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

	Derivative (Effective Portion)	into Income (Effective Portion)	into Income (Effective Portion)	on Derivative (Ineffective Portion)	Derivative (Ineffective Portion)
Interest rate swaps	$ 11,721	Interest expense	$ (1,958)		$ —
Commodity derivatives	(8,508)	Operating revenue	13,181	Operating revenue	(1,094)
Total	$ 3,213		$ 11,223		$ (1,094)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedges on our Condensed Consolidated Statement of Income for the three and six months ended June 30, 2010 and June 30, 2009 are presented below (in thousands):

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
for the Three and Six Months Ended June 30, 2010
Derivatives Not Designated as Hedging Instruments

		Three Months Ended	Six Months Ended
		June 30, 2010	June 30, 2010
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ 6,868	$ 4,209
Interest rate swap	Interest rate swap — unrealized (loss) gain	(24,918)	(27,953)
Foreign currency contracts	Operating revenue	(15)	(15)
		$ (18,065)	$ (23,759)

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Income
for the Three and Six Months Ended June 30, 2009
Derivatives Not Designated as Hedging Instruments

		Three Months Ended	Six Months Ended
		June 30, 2009	June 30, 2009
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ (9,239)	$ (17,364)
Interest rate swap	Interest rate swap — unrealized (loss) gain	31,706	46,469
Foreign currency contracts	Operating revenue	(350)	(107)

$ 22,117	$ 28,998

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value of our financial instruments at June 30, 2010 and December 31, 2009 is as follows (in thousands):

	June 30, 2010		December 31, 2009		June 30, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents	$ 64,033	$ 64,033	$ 112,901	$ 112,901	$ 122,351	$ 122,351
Restricted cash	$ 16,169	$ 16,169	$ 17,502	$ 17,502	$ —	$ —
Derivative financial instruments - assets	$ 64,315	$ 64,315	$ 41,524	$ 41,524	$ 80,629	$ 80,629
Derivative financial instruments - liabilities	$ 109,436	$ 109,436	$ 69,165	$ 69,165	$ 81,445	$ 81,445
Notes payable	$ 225,000	$ 225,000	$ 164,500	$ 164,500	$ 270,500	$ 270,500
Long-term debt, including current maturities	$ 994,669	$ 1,101,903	$ 1,051,157	$ 1,123,703	$ 751,329	$ 776,616

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 held in restricted cash accounts under our project financing agreement at Black Hills Wyoming.

Derivative Financial Instruments

Derivative Financial instruments are carried at fair value. Our fair value measurements are developed using a variety of inputs by our risk management group, which is independent of the trading function. These inputs include unadjusted quoted prices where available; prices published by various third-party providers; and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Some of our transactions take place in markets with limited liquidity and limited price visibility. Additionally, descriptions of the various instruments we use and the valuation method employed are included in Notes 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, no material proceedings have developed and no material proceedings have terminated during the first six 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 June 30, 2010, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Power Purchase Agreement and Purchase Option 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. This PPA also provided the City of Gillette, through JPB, 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. The City of Gillette notified Black Hills Power of its intent to exercise the option to purchase the 23% ownership interest in Wygen III and the transaction closed in July 2010. The PPA terminated upon the closing of the transaction (See Note 21).

Guarantees

We issued a guarantee for $6.0 million for a payment obligation arising from a contract to construct and purchase a new office building by Black Hills Utility Holdings. The office building is a 36,000 square foot office building located in Papillion, Nebraska. The guarantee will expire upon purchase of the building which is expected to be completed in 2011.

Black Hills Electric Generation issued a guarantee to the City of Pueblo, Colorado for the lesser of (a) the guaranteed obligations under the Annexation Agreement or (b) $10.0 million for the obligations of Colorado IPP relating to the construction of the 200 MW generation facility currently under construction. The guarantee will continue in force until December 31, 2011 and the current obligations do not exceed $2.9 million.

Other Commitments

Plans to construct a 180 MW power generation facility by our Colorado Electric utility and a 200 MW power generation facility by our Power Generation segment are progressing. Cost of construction is expected to be approximately $250 million to $260 million for Colorado Electric and $240 million to $265 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. As our plans progress, we are in the process of procuring or have procured contracts for the turbines, building construction and labor. As of June 30, 2010, committed contracts for purchased equipment and construction were 100% and 44 % complete, respectively, for the Colorado Electric utility and 79% and 38%, respectively, for the Power Generation segment.

(17) INCOME TAXES

Our effective tax rate for the six months ended June 30, 2010 was higher than for the six months ended June 30, 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 reflecting a re-measurement of a tax position in accordance with accounting for uncertain tax positions for our Oil and Gas segment.

(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) ACQUISITION

On June 1, 2010, Enserco expanded the commodities it markets through the acquisition of a coal marketing business from EDF for $2.25 million. Substantially all of the value of the net assets acquired was related to the portfolio of coal marketing contracts. On the June 1, 2010 acquisition date, the fair value of the net assets was approximately $2.4 million which was recorded in Derivative assets and Derivative liabilities. Additionally, we recognized $0.2 million negative goodwill, which was recorded in Other income, net on the accompanying Condensed Consolidated Income Statements. For the quarter ended June 30, 2010, Enserco recognized $4.2 million and $(0.4) million of unrealized and realized gross margins, respectively. Further information regarding these coal marketing contracts and activities is included in Note 13 of the Notes to Condensed Consolidated Financial Statements.

(21) SUBSEQUENT EVENTS

$200 Million Debt Offering

On July 16, 2010, pursuant to a public offering, we issued $200 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. We received proceeds of $198.7 million, net of underwriting fees. Estimated deferred financing costs were $1.7 million which will be amortized over the 10-year term of the debt. Proceeds were used to pay down a portion of borrowings on our Revolving Credit Facility and reduce issued letters of credit.

Partial Sale of Wygen III

On July 14, 2010, Black Hills Power sold a 23% ownership interest in Wygen III to the JBP for $62.0 million. The JBP exists for the purpose of, among other things, financing the electrical system of the City of Gillette. The transaction entitles the City of Gillette to an ownership interest of approximately 25.3 MW in the plant. The purchase terminates the current PPA with the City of Gillette, and the Wygen III Participation Agreement has been amended to include JPB. The Participation Agreement provides that the City of Gillette will pay Black Hills Power for administrative services and share in the costs of operating the plant for the life of the facility. The estimated amount of net fixed assets sold totaled $55.6 million.

Guarantees

On July 22, 2010, we issued a guarantee to Colorado Interstate Gas Company for $9.3 million for payment obligations of Black Hills Utilities Holdings, Inc. related to natural gas transportation, storage and services agreements. The guarantee expires July 31, 2011.

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 202,750 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 serve approximately 522,800 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, coal and related services.

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 and six months ended June 30, 2010, and our financial condition as of June 30, 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.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 73.

Significant Events

Wygen III Power Plant

On April 1, 2010, the Wygen III, 110 MW mine-mouth coal-fired power plant commenced commercial operations. As of June 30, 2010, Black Hills Power owned a 75% interest in the facility. As discussed below, Black Hills Power sold an additional 23% ownership interest in the facility during July 2010.

Energy Marketing Acquisition

In June 2010, our Energy Marketing segment expanded the commodities it markets to include coal through the acquisition of a coal marketing business for $2.25 million. The business will focus on sourcing coal from Wyoming's Powder River Basin for delivery to customers in the western United States.

Rate Case Settlements

Black Hills Power - South Dakota

In July 2010, the SDPUC approved a final revenue increase of $15.2 million, or 12.7%, for Black Hills Power customers. Interim rates representing a 20% revenue increase were in effect commencing April 1, 2010. A refund will be provided and has been accrued for the difference in rates.

Black Hills Power - Wyoming

In May 2010, the WPSC approved a final revenue increase of $3.1 million for Black Hills Power customers. The new rates were effective June 1, 2010.

Sale of Partial Ownership in Wygen III

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 replaced a previous PPA entered into in 1998. This new agreement also provided the City of Gillette, through JPB, with an option to purchase a 23% ownership interest, or approximately 25.3 MW, in Black Hills Power's Wygen III facility which commenced commercial operations on April 1, 2010. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette. The City of Gillette exercised this option on July 14, 2010 and the JPB purchased the 23% ownership interest in Wygen III for $62.0 million for which Black Hills Power will recognize a gain on the sale of approximately $5.0 million to $6.0 million. Under the Participation Agreement, Black Hills Power will continue to operate Wygen III and the City of Gillette will pay Black Hills Power for administrative services and its share in the costs of operating the plant for the life of the facility. The PPA dated March 2010 terminated upon the closing of the transaction.

Smart Grid Funding

In April 2010, we reached an agreement with the DOE 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. Our utilities expect to complete installation of these meters in 2011.

Results of Operations

Executive Summary and Overview

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Loss from continuing operations and Net loss for the three months ended June 30, 2010 was $8.7 million, or $0.22 per share, compared to Income from operations and Net income of $24.6 million, or $0.64 per share, reported for the same period in 2009. The 2010 Loss from continuing operations and Net loss includes a $16.2 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps while the 2009 Income from continuing operations and Net income includes a $20.6 million after-tax unrealized mark-to-market gain on these same interest rate swaps.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations for the six months ended June 30, 2010 was $22.8 million, or $0.58 per share, compared to $50.2 million, or $1.30 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 an $18.2 million non-cash after-tax unrealized mark-to-market loss on certain interest rate swaps. The 2009 Income from continuing operations includes a $30.2 million after-tax mark-to-market gain on these same interest rate swaps, a $27.8 million after-tax non-cash ceiling test impairment, and a $16.9 million after-tax gain on the sale of a 23.5% ownership interest in Wygen I.

Net income was $22.8 million, or $0.58 per share, in the first six months of 2010, compared to $51.0 million, or $1.32 per share, for the same period in 2009. In addition to the items mentioned above in income from continuing operations, the 2009 net income also includes $0.8 million of after-tax income from discontinued operations related to the IPP Transaction.

Business Group 2010 highlights are as follows:

Utilities Group

The Utilities Group's Income from continuing operations for the first six months of 2010 was $35.7 million, compared to $31.6 million for the same period in 2009. Our Electric Utilities were positively impacted by interim rates effective April 1, 2010 at Black Hills Power and an increase in off-system sales margins. Our Gas Utilities recorded increased margins due to the impact of recent rate increases not in effect for the entire year of 2009. Additional highlights of the Utilities Group include the following:

- The Wygen III generating facility commenced commercial operations on April 1, 2010. In September 2009, Black Hills Power filed a request for annual revenue increases of $32.0 million with the SDPUC to recover the costs associated with Wygen III and increases in other costs. On July 7, 2010, the SDPUC approved new rates representing $15.2 million in annual revenues which were effective retroactive to April 1, 2010;

- In October 2009, Black Hills Power filed a rate request for annual revenue increases of $3.8 million with the WPSC. On May 13, 2010, WPSC approved a rate increase of $3.1 million effective June 1, 2010 for Black Hills Power;

- In January 2010, Colorado Electric filed a request with the CPUC seeking a $22.9 million increase in annual revenues. On August 5, 2010, the CPUC approved a settlement agreement was for $17.9 million in annual revenues, with an effective date of August 6, 2010;

- In June 2010, Iowa Gas filed a request for a $4.7 million, or 2.9%, increase in annual revenues with the Iowa Utilities Board. An interim rate increase equal to 1.6% of revenues went into effect on June 18, 2010;

- We reached agreement with the DOE for smart grid funding through matching grants totaling $20.7 million, made available through the American Recovery and Reinvestment Act of 2009. During 2010, we have spent $1.2 million of the DOE grant funds and expect to have expended all grant funds by the end of 2011;

- In July 2010, Black Hills Power sold a 23% ownership interest in the Wygen III power generation facility to the JPB for $62.0 million. The JPB exists for the purpose of, among other things, financing the electric system of the City of Gillette, Wyoming. Under the terms of the purchase agreement, the City of Gillette will pay Black Hills Power for ongoing administrative services and share in the cost of operating the plant for the life of the facility;

- 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 generation project is expected to cost between $250 million and $260 million, of which $90.1 million has been expended on this project through June 30, 2010. Construction commenced in July 2010 subsequent to the City of Pueblo annexing our site into the city and the receipt of the final air permit from the State of Colorado Department of Public Health and Environment; and

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

Non-regulated Energy Group

Income from continuing operations was $11.2 million for the first six months of 2010 for the Non-regulated Energy Group compared to a Loss from continuing operations of $3.7 million in the same period in 2009. Highlights of the Non-regulated Energy Group include the following:

- In June 2010, Enserco expanded the commodities it markets through the acquisition of a coal marketing business for $2.25 million. During the second quarter of 2010, margins of $3.7 million were recognized as a result of activity in the acquired portfolio of coal marketing contracts;

- 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 at our Power Generation segment on the sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility;

- Plans to construct gas-fired generation at Colorado IPP to serve a 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, of which $61.1 million has been expended on this project through June 30, 2010. Construction commenced in July 2010 subsequent to the City of Pueblo annexing our site into the city and the receipt of the final air permit from the State of Colorado Department of Public Health and Environment; and

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In May 2010, Enserco entered into a two-year $250 million committed stand-alone credit facility. The new facility includes a $100 million accordion feature.

Corporate

Loss from continuing operations was $24.1 million for the first six months of 2010 compared to Income from continuing operations of $22.3 million in the same period in 2009. Highlights of the Corporate activities include the following:

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $18.2 million after-tax for the first six months of 2010 compared to a $30.2 million after-tax unrealized gain on these swaps for the same period in 2009; and

- On April 15, 2010, we entered into a new three-year $500 million Revolving Credit Facility, which includes a $100 million accordion feature, that will be used to fund working capital needs and general corporate purposes. The new facility replaces the 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues				
Utilities	$ 222,611	$ 211,944	$ 614,417	$ 605,341
Non-regulated Energy	48,680	45,405	99,206	89,951
	$ 271,291	$ 257,349	$ 713,623	$ 695,292
(Loss) income from continuing operations				
Utilities	$ 6,309	$ 4,983	$ 35,659	$ 31,566
Non-regulated Energy	4,193	2,818	11,244	(3,676)
Corporate	(19,161)	16,780	(24,128)	22,316
	$ (8,659)	$ 24,581	$ 22,775	$ 50,206
Net (loss) income				
Utilities	$ 6,309	$ 4,983	35,659	31,565
Non-regulated Energy	4,193	2,818	11,244	(3,675)
Corporate	(19,161)	16,780	(24,128)	23,082
	$ (8,659)	$ 24,581	$ 22,775	$ 50,972

Income from continuing operations decreased $33.2 million for the three months ended June 30, 2010 reflecting the following:

Utilities

- A $2.7 million increase in Electric Utilities earnings;

- A $1.3 million decrease in the Gas Utilities earnings;

Non-regulated Energy

-

A $0.1 million increase in Oil and Gas earnings;

•
A $3.6 million increase in Coal Mining earnings;

•
A $1.1 million decrease in Energy Marketing earnings;

•
A $1.2 million decrease in Power Generation earnings; and

Corporate

•
A $35.9 million decrease in Corporate activities.

Income from continuing operations decreased $27.4 million for the six months ended June 30, 2010 reflecting the following:

Utilities

- A $3.2 million increase in Electric Utilities earnings;
- A $0.9 million increase in the Gas Utilities earnings;

Non-regulated Energy

- A $28.2 million increase in Oil and Gas earnings;
- A $4.1 million increase in Coal Mining earnings;
- A $0.1 million decrease in Energy Marketing earnings;
- A $17.2 million decrease in Power Generation earnings; and

Corporate

- A $46.4 million decrease in Corporate activities.

Following are additional details regarding the results of operations from our Utilities and Non-regulated Energy Groups by business segment, and 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue — electric	$ 128,408	$ 112,998	$ 261,176	$ 235,174
Revenue — gas	7,857	5,823	23,898	20,922
Total revenue	136,265	118,821	285,074	256,096
Fuel and purchased power — electric	64,794	58,938	138,305	123,836
Purchased gas	4,581	2,705	15,772	12,962
Total fuel and purchased power	69,375	61,643	154,077	136,798
Gross margin — electric	63,614	54,060	122,871	111,338
Gross margin — gas	3,276	3,118	8,126	7,960
Total gross margin	66,890	57,178	130,997	119,298
Operating, general and administrative costs	35,956	32,371	68,724	64,287
Depreciation and amortization	11,897	10,967	23,086	21,925
Total operating expenses	47,853	43,338	91,810	86,212
Operating income	19,037	13,840	39,187	33,086
Interest expense, net	(8,448)	(9,486)	(16,702)	(16,985)
Other income	315	1,786	2,440	3,531
Income tax expense	(3,708)	(1,599)	(7,877)	(5,774)
Income from continuing operations and net income	$ 7,196	$ 4,541	$ 17,048	$ 13,858

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

Revenues (in thousands)	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Residential:				
Black Hills Power	$ 11,546	$ 10,391	$ 26,025	$ 24,672
Cheyenne Light	6,785	7,094	14,710	14,581
Colorado Electric	16,607	15,185	36,023	31,688
Total Residential	34,938	32,670	76,758	70,941
Commercial:				
Black Hills Power	16,104	14,551	30,643	29,194
Cheyenne Light	13,416	12,565	25,872	24,626
Colorado Electric	16,005	13,943	31,695	27,171
Total Commercial	45,525	41,059	88,210	80,991
Industrial:				
Black Hills Power	6,204	5,030	10,841	9,780
Cheyenne Light	2,882	2,758	5,412	5,291
Colorado Electric	6,841	6,961	13,785	15,053
Total Industrial	15,927	14,749	30,038	30,124
Municipal:				
Black Hills Power	748	660	1,401	1,296
Cheyenne Light	237	230	468	471

Colorado Electric	2,871	1,143	4,558	2,172
Total Municipal	3,856	2,033	6,427	3,939
Contract Wholesale:				
Black Hills Power	7,078	5,631	13,796	12,184
Off-system Wholesale:				
Black Hills Power	8,539	5,765	17,255	14,985
Cheyenne Light	2,119	1,952	4,710	3,932
Colorado Electric	2,903	2,974	10,236	7,027
Total Off-system Wholesale	13,561	10,691	32,201	25,944
Other:				
Black Hills Power	6,219	4,808	10,966	9,183
Cheyenne Light	789	112	1,701	213
Colorado Electric	515	1,245	1,079	1,655
Total Other	7,523	6,165	13,746	11,051
Total Revenues	$ 128,408	$ 112,998	$ 261,176	$ 235,174

Quantities Generated and Purchased (in MWh)	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Generated —				
Coal-fired:				
Black Hills Power	559,258	348,657	989,831	786,208
Cheyenne Light	181,475	185,172	357,899	376,728
Colorado Electric	55,993	56,856	126,244	123,331
Total Coal	796,726	590,685	1,473,974	1,286,267
Gas and Oil-fired:				
Black Hills Power	1,106	5,750	3,944	6,825
Cheyenne Light	—	—	—	—
Colorado Electric	93	199	93	199
Total Gas and Oil-fired	1,199	5,949	4,037	7,024
Total Generated:				
Black Hills Power	560,364	354,407	993,775	793,033
Cheyenne Light	181,475	185,172	357,899	376,728
Colorado Electric	56,086	57,055	126,337	123,530
Total Generated	797,925	596,634	1,478,011	1,293,291
Purchased —				
Black Hills Power	290,518	451,191	720,200	884,030
Cheyenne Light	151,570	154,286	344,427	312,273
Colorado Electric	487,956	493,319	1,029,158	980,845
Total Purchased	930,044	1,098,796	2,093,785	2,177,148
Total Generated and Purchased:				
Black Hills Power	850,882	805,598	1,713,975	1,677,063
Cheyenne Light	333,045	339,458	702,326	689,001
Colorado Electric	544,042	550,374	1,155,495	1,104,375
Total Generated and Purchased	1,727,969	1,695,430	3,571,796	3,470,439

Quantity Sold (in MWh)	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Residential:				
Black Hills Power	113,903	119,123	288,438	282,599
Cheyenne Light	59,152	59,100	133,972	130,226
Colorado Electric	137,581	134,557	304,610	277,230
Total Residential	310,636	312,780	727,020	690,055
Commercial:				
Black Hills Power	164,863	169,955	349,301	345,211
Cheyenne Light	143,915	141,555	289,124	287,100
Colorado Electric	181,641	169,698	352,595	319,164
Total Commercial	490,419	481,208	991,020	951,475
Industrial:				
Black Hills Power	101,425	93,984	188,088	179,968
Cheyenne Light	43,671	43,425	84,430	86,247
Colorado Electric	85,484	98,603	169,994	220,417
Total Industrial	230,580	236,012	442,512	486,632
Municipal:				
Black Hills Power	7,577	7,567	15,803	15,662
Cheyenne Light	679	682	1,613	1,707
Colorado Electric	33,638	10,571	49,416	17,991

Total Municipal	41,894	18,820	66,832	35,360
Contract Wholesale:				
Black Hills Power	120,258	143,248	288,723	311,927
Off-system Wholesale:				
Black Hills Power	299,064	230,617	530,111	474,403
Cheyenne Light	63,995	73,947	148,262	144,051
Colorado Electric	73,513	94,865	233,288	200,808
Total Off-system Wholesale	436,572	399,429	911,661	819,262
Total Quantity Sold:				
Black Hills Power	807,090	764,494	1,660,464	1,609,770
Cheyenne Light	311,412	318,709	657,401	649,331
Colorado Electric	511,857	508,294	1,109,903	1,035,610
Total Quantity Sold	1,630,359	1,591,497	3,427,768	3,294,711
Losses and Company Use:				
Black Hills Power	43,792	41,104	53,511	67,293
Cheyenne Light	21,633	20,749	44,925	39,670
Colorado Electric	32,185	42,080	45,592	68,765
Total Losses and Company Use	97,610	103,933	144,028	175,728

Total Energy	1,727,969	1,695,430	3,571,796	3,470,439

	Three Months Ended June 30,					
Degree Days	2010			2009		
Heating Degree Days:	Actual	Variance from Normal		Actual	Variance from Normal	
Actual —						
Black Hills Power	904	9	%	1,273	28	%
Cheyenne Light	1,308	6	%	1,261	2	%
Colorado Electric	647	1	%	579	(10	)%
Cooling Degree Days:						
Actual —						
Black Hills Power	65	(37	)%	51	(50	)%
Cheyenne Light	35	(17	)%	24	(43	)%
Colorado Electric	280	30	%	184	(15	)%

	Six Months Ended June 30,					
Degree Days	2010			2009		
Heating Degree Days:	Actual	Variance from Normal		Actual	Variance from Normal	
Actual —						
Black Hills Power	4,296	4	%	4,527	5	%
Cheyenne Light	4,418	1	%	4,085	(7	)%

Colorado Electric	3,424	4 %	2,949	(10)%
Cooling Degree Days:				
Actual —				
Black Hills Power	65	(35)%	51	(50)%
Cheyenne Light	35	(17)%	24	(43)%
Colorado Electric	280	30 %	184	(15)%

	Electric Utilities Power Plant Availability			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Coal-fired plants	90.0 % (a)	81.8 % (b)	91.3 %	89.5 % (b)
Other plants	97.4 %	92.6 %	98.6 %	96.0 %
Total availability	92.6 %	86.0 %	93.9 %	92.0 %

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(a) Reflects addition of Wygen III which commenced commercial operations on April 1, 2010. Wygen III's availability during the three months ended June 30, 2010 was 85.8%.

(b) Reflects major maintenance outages at Neil Simpson I and Neil Simpson II coal-fired plants. The outages were extended on both units to repair major rotor damage discovered during the overhauls. The Neil Simpson I outage was scheduled for 31 days and was subsequently extended to 39 days. The Neil Simpson II outage was scheduled for 18 days and was subsequently extended to 27 days.

Cheyenne Light Natural Gas Distribution

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues (in thousands):				
Residential	$ 4,770	$ 3,634	$ 14,283	$ 12,646
Commercial	2,222	1,631	7,055	6,060
Industrial	663	373	2,121	1,807
Other	202	185	439	409
Total Revenues	$ 7,857	$ 5,823	$ 23,898	$ 20,922
Gross Margins (in thousands):				
Residential	$ 2,298	$ 2,089	$ 5,550	$ 5,366
Commercial	752	746	1,969	1,917
Industrial	60	98	227	268
Other	166	185	380	409
Total Gross Margins	$ 3,276	$ 3,118	$ 8,126	$ 7,960
Volumes Sold (Dth):				
Residential	555,636	553,518	1,695,179	1,568,764
Commercial	331,723	333,213	992,841	917,636
Industrial	135,370	135,790	377,545	383,115
Total Volumes Sold	1,022,729	1,022,521	3,065,565	2,869,515

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Income from continuing operations was $7.2 million for the three months ended June 30, 2010 compared to $4.5 million for the three months ended June 30, 2009 as a result of:

Gross margin: Gross margin increased $9.7 million primarily due to an increase of $5.9 million related to the impact of the outcome of the Black Hills Power rate case where interim rates went into effect on April 1, 2010, an increase of $1.2 million for updated transmission cost adjustments at Colorado Electric, an increase of $1.0 million in off-system sales margins resulting from higher prices, and an increase of $1.2 million associated with an intercompany shared services agreement.

Operating, general and administrative costs: Operating, general and administrative costs increased $3.6 million primarily due to additional costs of $0.9 million associated with Wygen III which commenced commercial operations on April 1, 2010, increased labor and employee benefit costs, and increased intercompany costs of $1.2 million associated with a shared services agreement.

Depreciation and amortization: Depreciation and amortization increased $0.9 million primarily due to commencement of depreciation on the Wygen III plant commenced commercial operations on April 1, 2010.

Interest expense, net: Interest expense, net decreased $1.0 million due to an increase of $1.8 million for AFUDC associated with the borrowed funds for the Colorado Electric plant construction partially offset by higher interest expense of $1.3 million compared to the same period in the prior year resulting from a change in debt structure from short-term debt to longer-term debt.

Other income: Other income decreased $1.5 million primarily due to lower AFUDC-equity which decreased upon the placement of Wygen III into commercial operations on April 1, 2010.

Income tax expense: Income tax expense increased $2.1 million primarily due to an increase in earnings compared to the same period in the prior year and a higher effective tax rate resulting from the lower benefit from AFUDC-equity which decreased upon commercial operations of Wygen III.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations was $17.0 million in the first six months of 2010 compared to $13.9 million in the first six months of 2009 as a result of:

Gross margin: Gross margin increased $11.7 million primarily due to a $5.9 million increase related to the impact of the outcome of the Black Hills Power rate case where interim rates went into effect on April 1, 2010, a $2.9 million increase in off-system sales margin resulting from higher prices, and a $3.0 million increase in intercompany revenues from a shared services agreement.

Operating, general and administrative costs: Operating, general and administrative costs increased $4.4 million primarily due to costs of $0.9 million associated with Wygen III which commenced commercial operation on April 1, 2010, an increase of $1.2 million in labor and employee benefit costs, an increase of $0.9 million in property taxes, and an increase of $2.1 million in intercompany costs from a shared services agreement.

Depreciation and amortization: Depreciation and amortization increased $1.2 million primarily due to commencement of depreciation on the Wygen III plant placed into service on April 1, 2010.

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

Other income: Other income decreased $1.1 million primarily due to decreased AFUDC-equity associated with the construction of our Wygen III facility.

Income tax expense: The effective tax rate for the six months ended June 30, 2010 was comparable to the same period in the prior year.

Gas Utilities

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Sales revenue:				
Natural gas — regulated	$ 79,727	$ 86,760	$ 315,182	$ 335,741
Other — non-regulated services	7,388	6,578	15,103	13,934
Total sales revenue	87,115	93,338	330,285	349,675
Cost of sales:				
Natural gas — regulated	39,324	46,601	202,751	227,816
Other — non-regulated services	3,754	3,891	7,772	8,461
Total cost of sales	43,078	50,492	210,523	236,277
Gross margin	44,037	42,846	119,762	113,398
Operating, general and administrative costs	32,091	30,236	66,449	63,232
Gain on sale of operating assets	—	—	(2,683)	—
Depreciation and amortization	6,774	7,499	13,819	15,680
Total operating expenses	38,865	37,735	77,585	78,912
Operating income	5,172	5,111	42,177	34,486
Interest expense, net	(6,824)	(4,334)	(13,009)	(6,569)
Other expense	260	(83)	49	(118)
Income tax benefit (expense)	506	(252)	(10,605)	(10,091)
(Loss) income from continuing operations and net (loss) income	$ (886)	$ 442	$ 18,612	$ 17,708

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

Revenues	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Residential:				
Colorado	$ 10,597	$ 10,740	$ 33,449	$ 38,150
Nebraska	16,676	18,864	73,770	78,146
Iowa	14,896	16,867	63,575	71,411
Kansas	10,585	11,182	43,929	41,888
Total Residential	52,754	57,653	214,723	229,595
Commercial:				
Colorado	2,239	2,481	7,228	8,313
Nebraska	5,250	6,364	26,660	28,323
Iowa	6,224	6,888	29,013	32,375
Kansas	3,054	3,150	14,304	13,566
Total Commercial	16,767	18,883	77,205	82,577
Industrial:				
Colorado	249	579	293	709
Nebraska	636	577	2,141	2,090
Iowa	272	34	1,183	651
Kansas	3,548	3,325	4,335	4,585
Total Industrial	4,705	4,515	7,952	8,035
Transportation:				
Colorado	170	186	451	362
Nebraska	1,924	1,969	6,573	5,922
Iowa	758	944	1,958	2,044
Kansas	1,046	1,190	2,984	2,796
Total Transportation	3,898	4,289	11,966	11,124
Other:				
Colorado	29	29	56	58
Nebraska	484	539	1,096	1,186
Iowa	138	267	582	693

Kansas	952	585	1,602	2,473
Total Other	1,603	1,420	3,336	4,410
Total Regulated	79,727	86,760	315,182	335,741
Non-regulated Services	7,388	6,578	15,103	13,934
Total Revenues	$ 87,115	$ 93,338	$ 330,285	$ 349,675

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

Gross Margins	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Residential:				
Colorado	$ 3,965	$ 3,567	$ 10,555	$ 8,682
Nebraska	9,714	8,995	26,050	24,130
Iowa	8,620	8,597	24,075	24,162
Kansas	6,075	6,292	16,292	15,348
Total Residential	28,374	27,451	76,972	72,322
Commercial:				
Colorado	693	649	1,910	1,616
Nebraska	2,039	2,197	7,178	6,941
Iowa	2,016	2,194	6,629	7,316
Kansas	1,200	1,276	3,780	3,495
Total Commercial	5,948	6,316	19,497	19,368
Industrial:				
Colorado	68	149	91	184
Nebraska	71	70	234	212
Iowa	33	24	118	90
Kansas	480	536	663	750
Total Industrial	652	779	1,106	1,236
Transportation:				
Colorado	170	186	451	362
Nebraska	1,924	1,969	6,573	5,921
Iowa	758	945	1,958	2,045
Kansas	1,046	1,191	2,997	2,797
Total Transportation	3,898	4,291	11,979	11,125
Other:				
Colorado	29	28	56	57
Nebraska	483	539	1,095	1,187
Iowa	139	267	583	693

Kansas	880	488	1,143	1,937
Total Other	1,531	1,322	2,877	3,874
Total Regulated	40,403	40,159	112,431	107,925
Non-regulated Services	3,634	2,687	7,331	5,473
Total Gross Margins	$ 44,037	$ 42,846	$ 119,762	$ 113,398

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

Volumes Sold	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Residential:				
Colorado	1,150,169	1,141,526	3,971,016	3,493,140
Nebraska	1,384,365	1,740,296	7,720,752	7,440,074
Iowa	1,200,114	1,487,113	6,594,008	6,952,670
Kansas	836,716	1,062,405	4,405,333	4,009,303
Total Residential	4,571,364	5,431,340	22,691,109	21,895,187
Commercial:				
Colorado	269,435	293,801	924,808	803,279
Nebraska	652,800	865,365	3,197,924	3,201,025
Iowa	799,463	911,543	3,707,567	3,734,480
Kansas	343,704	408,154	1,688,852	1,529,081
Total Commercial	2,065,402	2,478,863	9,519,151	9,267,865
Industrial:				
Colorado	45,902	118,536	49,656	130,793
Nebraska	117,670	112,284	337,640	314,765
Iowa	46,235	8,551	177,501	90,683
Kansas	706,933	811,964	817,557	1,001,218
Total Industrial	916,740	1,051,335	1,382,354	1,537,459
Transportation:				
Colorado	176,676	196,826	475,219	431,800
Nebraska	5,558,285	5,830,746	13,548,913	13,414,429
Iowa	3,944,164	3,238,495	9,256,912	7,305,769
Kansas	3,092,475	3,524,951	7,302,303	7,017,578
Total Transportation	12,771,600	12,791,018	30,583,347	28,169,576
Other:				
Colorado	—	—	—	—
Nebraska	173	245	1,149	1,135
Iowa	10,232	12,335	52,529	48,508
Kansas	11,844	17,936	70,853	77,518

Total Other	22,249	30,516	124,531	127,161
Total volumes	20,347,355	21,783,072	64,300,492	60,997,248

Degree Days	Three Months Ended June 30, 2010			Six Months Ended June 30, 2010		
Heating Degree Days:	Actual	Variance From Normal		Actual	Variance From Normal	
Colorado	856	(10	)%	3,693	(3	)%
Nebraska	495	(13	)%	3,867	3	%
Iowa	556	(30	)%	4,081	(8	)%
Kansas*	427	(5	)%	3,118	4	%
Combined Gas Utilities Heating Degree Days	544	(17	)%	3,747	(1	)%

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Degree Days	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	892	(7)%	3,418	(11)%
Nebraska	562	—%	3,565	1%
Iowa	797	8%	4,495	(8)%
Kansas*	484	—%	2,748	(5)%
Combined Gas Utilities Heating Degree Days	654	—%	3,643	(4)%

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

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Loss from continuing operations was $0.9 million in the three months ended June 30, 2010 compared to Income from continuing operations of $0.4 million in the three months ended June 30, 2009 as a result of:

Gross margin: Gross margins increased $1.2 million primarily due to increased interim rates at Iowa Gas and Nebraska Gas, and an approved surcharge at Kansas Gas which were effective subsequent to the second quarter of 2009, partially offset by lower volumes.

Operating, general and administrative costs: Operating, general and administrative costs increased $1.9 million primarily due to increases in labor and employee benefit costs.

Depreciation and amortization: Depreciation and amortization decreased $0.7 million primarily due to assets that became fully depreciated during 2009.

Interest expense, net: Interest expense, net increased $2.5 million primarily resulting from the assignment of longer-term debt to adjust the assigned capital structure.

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

Income tax benefit (expense): The effective tax rate for the three months ended June 30, 2010 was comparable to the same period in the prior year.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations was $18.6 million in the first six months of 2010 compared to $17.7 million in the first six months of 2009 as a result of:

Gross margin: Gross margins increased $6.4 million due to higher volumes on more heating degree days and increased interim rates at Iowa Gas and Nebraska Gas, approved rates at Colorado Gas, and an approved surcharge at Kansas Gas which were effective subsequent to the second quarter of 2009.

Operating, general and administrative costs: Operating, general and administrative costs increased $3.2 million primarily due to increases in labor and employee benefit costs.

Gain on sale of operating assets: The gain on sale of operating assets of $2.7 million represents assets sold by Nebraska Gas to the City of Omaha, Nebraska after a portion of Nebraska Gas' service territory was annexed by the City.

Depreciation and amortization: Depreciation and amortization decreased $1.9 million primarily due to assets becoming fully depreciated during 2009.

Interest expense, net: Interest expense, net increased $6.4 million primarily from the assignment of debt to adjust the assigned capital structure and an increased interest rate associated with the assignment of longer-term debt.

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

Income tax expense: The effective tax rate for the six months ended June 30, 2010 was comparable to the same period in the prior year.

Regulatory Matters — Utilities Group

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

							Approved Capital Structure	
	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Equity	Debt
Nebraska Gas	Gas	11/2006	9/2007	$ 16.3	$ 9.2	10.4 %	51.0 %	49.0 %
Nebraska Gas (1)	Gas	12/2009	Pending	$ 12.1	Pending	Pending	Pending	Pending
Iowa Gas	Gas	6/2008	7/2009	$ 13.6	$ 10.8	10.1 %	51.4 %	48.6 %
Iowa Gas (2)	Gas	6/2010	Pending	$ 4.7	Pending	Pending	Pending	Pending
Colorado Gas	Gas	6/2008	4/2009	$ 2.7	$ 1.4	10.3 %	50.5 %	49.5 %
Kansas Gas	Gas	5/2009	10/2009	$ 0.5	$ 0.5	10.2 %	50.7 %	49.3 %
Black Hills Power (3)	Electric	9/2008	1/2009	$ 4.5	$ 3.8	10.8 %	57.0 %	43.0 %
Black Hills Power (4)	Electric	9/2009	7/2010	$ 32.0	$ 15.2	Black Box	Black Box	Black Box
Black Hills Power (5)	Electric	10/2009	6/2010	$ 3.8	$ 3.1	10.5 %	52.0 %	48.0 %
Colorado Electric (6)	Electric	1/2010	8/2010	$ 22.9	$ 17.9	10.5 %	52.0 %	48.0 %

(1) On December 1, 2009, Nebraska Gas filed with the NPSC 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. A commission decision is anticipated by mid-August 2010.

(2) On June 8, 2010, Iowa Gas filed a request with the Iowa Utilities Board for a $4.7 million, or 2.9%, revenue increase to recover the cost of capital investments we made in our gas distribution system and other expense increases incurred since December 2008. Interim rates, subject to refund, equal to a 1.6% increase in revenues went into effect on June 18, 2010.

(3) 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.

(4) 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 requested a $32.0 million, or 26.6%, increase in annual utility revenues. In March 2010, the SDPUC approved a 20% increase in interim revenues, subject to refund, effective April 1, 2010 for South Dakota customers. On July 7, 2010, the SDPUC approved a final revenue increase of $15.2 million, or 12.7%, and a base rate increase of $22 million, or 19.4% with an effective date of April 1, 2010. The approved capital structure and return on equity are confidential.

As part of the settlement stipulation, Black Hills power agreed (1) to credit customers 65% of off-system income with a minimum of $2 million per year; (2) that rates will include a SD Surplus Energy Credit of $2.5 million in year one (fiscal year ending March 2011), $2.25 million in year two, $2.0 million in year three and zero thereafter; and (3) a moratorium of three years on any rate case filings excluding any extraordinary events as defined in the stipulation agreement.

(5) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting an electric revenue increase of $3.8 million to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred since 1995. On May 4, 2010, Black Hills Power filed a settlement stipulation agreement with the WPSC for a $3.1 million increase in annual revenues. On May 13, 2010, WPSC approved these new rates based on a return on equity of 10.5% with a capital structure of 52% equity and 48% debt. Rates went into effect on June 1, 2010.

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

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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenue	$ 18,658	$ 17,829	$ 38,401	$ 34,340
Operating, general and administrative costs	10,499	10,049	20,233	20,069
Depreciation, depletion and amortization	6,842	6,197	12,953	15,138
Impairment of long-lived assets	—	—	—	43,301
Total operating expenses	17,341	16,246	33,186	78,508
Operating income (loss)	1,317	1,583	5,215	(44,168)
Interest expense	(1,391)	(1,411)	(2,173)	(2,452)
Other income	239	168	542	330
Income tax benefit (expense)	56	(211)	(1,015)	20,699
Income (loss) from continuing operations and net income (loss)	$ 221	$ 129	$ 2,569	$ (25,591)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Fuel production:				
Bbls of oil sold	84,427	95,900	168,818	195,270
Mcf of natural gas sold	2,356,674	2,653,600	4,508,850	5,342,500
Mcf equivalent sales	2,863,236	3,229,000	5,521,758	6,514,300

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Average price received: [a]				
Gas/Mcf [b]	$ 4.85	$ 4.39	$ 5.36	$ 4.65
Oil/Bbl	$ 89.98	$ 58.32	$ 82.19	$ 54.30
Depletion expense/Mcfe	$ 2.15	$ 1.67	$ 2.08	$ 2.09

(a) Net of hedge settlement gains/losses

(b) Exclusive of gas liquids

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Following are summaries of LOE/Mcfe:

	Three Months Ended June 30, 2010			Three Months Ended June 30, 2009			
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total	
New Mexico	$ 1.36	$ 0.33	$ 1.69	$ 1.18	$ 0.28	$ 1.46	
Colorado	0.38	0.62	1.00	1.25	0.37	1.62	
Wyoming	1.27	—	1.27	1.52	—	1.52	
All other properties	0.65	—	0.65	0.67	0.02	0.69	(a)
All locations	$ 1.09	$ 0.20	$ 1.29	$ 1.17	$ 0.16	$ 1.33	(a)

	Six Months Ended June 30, 2010			Six Months Ended June 30, 2009			
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total	
New Mexico	$ 1.39	$ 0.35	$ 1.74	$ 1.20	$ 0.27	$ 1.47	
Colorado	0.45	0.72	1.17	1.00	0.41	1.41	
Wyoming	1.38	—	1.38	1.47	—	1.47	
All other properties	0.79	0.03	0.82	0.82	0.07	0.89	(a)
All locations	$ 1.17	$ 0.22	$ 1.39	$ 1.17	$ 0.17	$ 1.34	(a)

(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 June 30, 2010 Compared to Three Months Ended June 30, 2009. Income from continuing operations was $0.2 million for the three months ended June 30, 2010 compared to $0.1 million for the same period in 2009 as a result of:

Revenue: Revenue increased $0.8 million primarily due to a 10% increase in the average hedged price of natural gas and a 54% increase in average hedged price of oil, partially offset by a 12% decline in oil volumes and an 11% decline in gas volumes and the impact of a $1.2 million charge for the reallocation of certain net revenues associated with reversionary ownership. The volume decline was largely driven by natural production declines from producing properties, reflecting reduced capital deployment during 2010 and 2009.

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

Depreciation, depletion and amortization: Depreciation, depletion and amortization increased $0.6 million due to a higher depletion rate partially offset by lower volumes. The depletion rate for the three months ended June 30, 2010 compared to the same period in the prior year is a result of a favorable depletion true-up in 2009 compared to an unfavorable true-up in 2010.

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

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

Income tax benefit (expense): Income tax benefit (expense) for the second quarter of 2010 and 2009 reflected an adjustment for depletion rates.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations was $2.6 million for the six months ended June 30, 2010 compared to a Loss from continuing operations of $25.6 million in the same period in 2009 as a result of:

Revenue: Revenue increased $4.1 million due to a 15% increase in the average hedged price of natural gas and a 51% increase in average hedged price of oil, partially offset by a 16% decline in gas volumes, a 14% decline in oil volumes and the impact of a $1.2 million charge for the reallocation of certain net revenues associated with reversionary ownership. The volume decline was largely driven by natural production declines from producing properties, reflecting reduced capital deployment during 2010 and 2009.

Operating, general and administrative costs: Operating, general and administrative costs for the first six months of 2010 are comparable to the same period in the prior year.

Depreciation, depletion and amortization: Depreciation, depletion and amortization decreased $2.2 million primarily due to lower volumes.

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

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

Income tax expense: The first six months of 2009 included a $3.8 million positive adjustment of a previously recorded tax position.

Coal Mining

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue	$ 15,049	$ 13,493	$ 29,029	$ 27,895
Operating, general and administrative costs	9,050	10,900	19,291	21,095
Depreciation, depletion and amortization	3,321	3,588	6,211	7,574
Total operating expenses	12,371	14,488	25,502	28,669
Operating income	2,678	(995)	3,527	(774)
Interest income, net	787	272	1,105	583

Other income	527	505	1,083	705
Income tax expense	(918)	(281)	(1,295)	(195)
Income (loss) from continuing operations and net income	$ 3,074	$ (499)	$ 4,420	$ 319

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Tons of coal sold	1,459	1,363	2,851	2,870
Cubic yards of overburden moved	3,752	3,473	7,323	6,635

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Income from continuing operations was $3.1 million for the three months ended June 30, 2010 compared to a Loss from continuing operations of $0.5 million in the same period in 2009, as a result of:

Revenue: Revenue increased $1.6 million primarily due to a 4% increase in average price received, which reflects the impact of regulated sales prices determined in part by an approved return on our coal mine's cost-depreciated investment base, and a 9% increase in tons of coal sold as a result of sales to the Wygen III power plant, which began commercial operations on April 1, 2010, partially offset by the impact on sales volumes from customer plant outages.

Operating, general and administrative costs: During 2010, we received approval from the State of Wyoming's Department of Environmental Quality for a revised post mining topography plan. The new plan includes a more efficient method of conducting final reclamation of our mine site by re-assessing the handling of overburden. Accordingly, overburden yards meeting backfill requirements were modified in the three months ended June 30, 2010. This resulted in a reduction to overburden removal costs of approximately $2.0 million. Operating costs also decreased due to lower mining. Cubic yards of overburden moved increased 8%.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense decreased $0.3 million due to lower estimated future reclamation costs amortized over the life of the uncovered coal, partially offset by increased depreciation on equipment.

Interest income, net: Interest income, net increased $0.5 million due to increased advances to affiliates at higher interest rates.

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

Income tax expense: Income tax expense increased due to higher pre-tax earnings during the three months ended June 30, 2010, and during the three months ended June 30, 2009, the tax benefit generated by percentage depletion had a more significant effect on the income tax provision than in the current period.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations was $4.4 million for the six months ended June 30, 2010 compared to $0.3 million for the same period in 2009 as a result of:

Revenue: Revenue increased $1.1 million due to 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 an approved return on our coal mine's cost-depreciated investment base. Tons of coal sold were comparable to the prior year as sales associated with the commencement of commercial operations of Wygen III were offset by customer plant outages and lower demand.

Operating, general and administrative costs: During 2010, we received approval from the State of Wyoming's Department of Environmental Quality for a revised post mining topography plan. The new plan includes a more efficient method of conducting final reclamation of our mine site by re-assessing the handling of overburden. Accordingly, overburden yards meeting backfill requirements were modified in the six months ended June 30, 2010. This resulted in a reduction to overburden removal costs of approximately $2.0 million. Operating costs also decreased due to lower mining taxes. Cubic yards of overburden moved increased 10%.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense decreased approximately $1.4 million due to lower estimated future reclamation costs amortized over the life of our inventory of uncovered coal, partially offset by increased depreciation on equipment.

Interest income, net: Interest income, net increased $0.5 million due to increased advances to affiliates and higher interest rates.

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 six months of 2010, and during the first six months of 2009, the tax benefit generated by percentage depletion had a more significant effect on the income tax provision.

Energy Marketing

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue and gross margins —				
Realized gas marketing gross margin	$ 2,046	$ 11,384	$ 12,567	$ 22,354
Unrealized gas marketing gross margin	44	(5,642)	(960)	(6,978)
Realized oil marketing gross margin	1,042	5,131	2,574	8,108
Unrealized oil marketing gross margin	2,041	(3,135)	764	(8,927)
Realized coal marketing gross margin	(443)	—	(443)	—
Unrealized coal marketing gross margin	4,165	—	4,165	—
Total Revenue and Gross Margins	8,895	7,738	18,667	14,557
Operating, general and administrative costs	6,032	4,040	11,458	9,169
Depreciation and amortization	127	129	259	262
	6,159	4,169	11,717	9,431

Total operating expenses				
Operating income	2,736	3,569	6,950	5,126
Interest expense, net	(800)	(121)	(1,562)	(63)
Other income	184	3	153	17
Income tax expense	(793)	(1,241)	(2,021)	(1,833)
Income from continuing operations and net income	$ 1,327	$ 2,210	$ 3,520	$ 3,247

Following is a summary of average daily quantities marketed:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Natural gas physical sales — MMBtus	1,348,887	1,582,900	1,549,913	1,916,000
Crude oil physical sales — Bbls	20,935	11,846	17,203	11,456
Coal physical sales — Tons (a)	27,972	—	27,972	—

(a) The tons of coal marketed are for the period June 1, 2010 to June 30, 2010

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Income from continuing operations was $1.3 million for the three months ended June 30, 2010 compared to $2.2 million in the same period in 2009 as a result of:

Revenue and gross margin: Revenue and gross margin increased $1.2 million primarily driven by unrealized gains on our portfolio of coal marketing contracts acquired on June 1, 2010. The contracts we acquired included a significant "long" coal position. An increase in the market price of coal during June 2010 combined with this "long" position drove the unrealized coal marketing margins during the period. The benefit from coal marketing was supplemented by strong results from increased crude oil volumes marketed and was partially offset by lower margins from decreased natural gas marketing volumes.

Operating, general and administrative costs: Operating, general and administrative costs increased $2.0 million primarily due to increased provision for compensation expense on higher margins and increased bank fees as a result of higher letter of credit costs due to a higher utilization level.

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

Interest expense, net: Interest expense, net increased $0.7 million primarily due to increased amortization of financing costs related to the committed Enserco Credit Facility and decreased interest income on lower cash balances.

Other income: Other income for the three months ended June 30, 2010 is comparable to the same period in the prior year.

Income tax expense: The effective income tax rate for the three months ended June 30, 2010 was comparable to the same period in the prior year.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations was $3.5 million for the six months ended June 30, 2010 compared to $3.2 million for the same period in 2009 as a result of:

Revenue and gross margin: Revenue and gross margin increased $4.1 million driven by unrealized gains on our portfolio of coal marketing contracts acquired on June 1, 2010. The contracts we acquired included a significant "long" coal position. An increase in the market price of coal during June 2010 combined with this "long" position drove the unrealized coal marketing margins during the period. The benefit from coal marketing was supplemented by strong results from increased crude oil volumes marketed and was partially offset by lower margins from decreased natural gas marketing volumes.

Operating, general and administrative costs: Operating, general and administrative costs increased $2.3 million primarily due to increased provision for compensation expense on higher margins and increased bank fees as a result of higher letter of credit costs due to a higher utilization level.

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

Interest expense, net: Interest expense, net increased $1.5 million primarily due to increased amortization of financing costs related to the committed Enserco Credit Facility.

Other income: Other income for the six months ended June 30, 2010 is comparable to the same period in the prior year.

Income tax expense: The effective tax rate for the six months ended June 30, 2010 was comparable to the same period in the prior year.

Power Generation

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenue	$ 6,679	$ 7,215	$ 14,747	$ 14,834
Cost of sales	2,055	1,317	3,742	2,615
Gross margin	4,624	5,898	11,005	12,219
Operating, general and administrative costs	3,136	2,085	4,823	3,726
Depreciation and amortization	1,298	945	2,326	1,851
Gain on sale of operating asset	—	—	—	(25,971)
Total operating expense (income)	4,434	3,030	7,149	(20,394)
Operating income	190	2,868	3,856	32,613
Interest expense, net	(1,986)	(3,057)	(3,983)	(6,040)
Other income	1,171	1,380	1,160	994
Income tax benefit (expense)	209	(433)	(369)	(9,656)
(Loss) income from continuing operations and net (loss) income	$ (416)	$ 758	$ 664	$ 17,911

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Contracted power plant fleet availability:				
Coal-fired plant	98.9 % *	92.4 %	99.5 %	94.0 %
Natural gas-fired plants	100.0 %	98.5 %	100.0 %	98.3 %
Total availability	99.3 %	94.9 %	99.7 %	95.7 %

* Contracted availability was not impacted by plant outage at Wygen I as a result of replacement power provision in the contract.

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Loss from continuing operations was $0.4 million for the three months ended June 30, 2010 compared to Income from continuing operations of $0.8 million in the same period in 2009 as a result of:

Revenue: Revenue decreased $0.5 million primarily due to a major overhaul and forced outage at Wygen I.

Cost of Sales: Cost of sales increased $0.7 million primarily as a result of the purchase of replacement power due to a major overhaul and forced outage at Wygen I.

Operating, general and administrative costs: Operating, general and administrative costs increased $1.1 million primarily due to increased maintenance costs from an extended outage at Wygen I.

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

Interest expense, net: Interest expense, net decreased $1.1 million primarily due to a decrease in debt from an intercompany debt restructuring partially offset by interest expense associated with the $120.0 million project financing at Black Hills Wyoming.

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

Income tax benefit (expense): The effective tax rate for the three months ended June 30, 2010 was comparable to the same period in the prior year.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Income from continuing operations was $0.7 million for the six months ended June 30, 2010 compared to $17.9 million in the same period in 2009 as a result of:

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

Cost of Sales: Cost of sales increased $1.1 million primarily as a result of purchase of replacement power due to an extended outage at Wygen I.

Operating, general and administrative costs: Operating, general and administrative costs increased $1.1 million primarily due to maintenance costs for an extended outage at Wygen I.

Depreciation and amortization: Depreciation and amortization was 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 in the Wygen I generating facility to MEAN.

Interest expense, net: Interest expense, net decreased $2.1 million primarily due to a decrease in debt from an intercompany debt restructuring partially offset by the interest expense associated with the $120.0 million project financing at Black Hills Wyoming.

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

Income tax expense: The effective tax rate for the six months ended June 30, 2010 was comparable to the same period in the prior year.

Corporate

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009. Loss from continuing operations was $19.2 million for the three months ended June 30, 2010 compared to Income from continuing operations of $16.8 million for the three months ended June 30, 2009 as a result of:

- Unrealized net, mark-to-market after-tax losses for the quarter ended June 30, 2010 of approximately $16.2 million on certain interest rate swaps compared to a $20.6 million unrealized mark-to-market after-tax gain on certain interest rate swaps in the prior period; and

- A $1.3 million decrease in net interest expense.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009. Loss from continuing operations was $24.1 million compared to Income from continuing operations of $22.3 million as a result of:

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Unrealized net, mark-to-market after-tax losses for the six months ended June 30, 2010 of approximately $18.2 million on certain interest rate swaps compared to a $30.2 million unrealized mark-to-market after-tax gain on certain interest rate swaps in the prior period; and

- A $2.5 million decrease in net interest expense.

Discontinued Operations

Earnings from discontinued operations were $0.8 million, net of tax, for the six month period ended June 30, 2009 relating to working capital and tax adjustments associated with the IPP Transaction.

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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 six month period ended June 30, 2010, we generated sufficient cash flow to meet our operating needs, to 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 the construction of utility and IPP generation to serve our Colorado Electric utility, from internally generated cash resources and external financings.

Cash flows from operations of $144.0 million for the six month period ended June 30, 2010 represent a $102.3 million decrease compared to the same period in the prior year. The change in cash provided by operating activities was due to a $27.4 million decrease in income from continuing operations and changes in working capital as follows:

- A $60.6 million decrease in cash flows from working capital changes. This decrease primarily resulted from a $51.8 million decrease in cash flows from increases in materials, supplies and fuel, a $70.8 million decrease from changes in accounts receivable and other current assets and a $62.1 million increase from changes in 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 segment 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 $4.1 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 period-end commodity prices;

- A $15.2 million decrease in cash flows from the net change in derivative assets and liabilities primarily from commodity price fluctuations associated with normal operations of our Energy Marketing segment and our Oil and Gas segment;

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

- A $74.4 million increase to adjust for the non-cash effect of unrealized mark-to-market losses on interest rate swaps; and

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A $6.1 million decrease in cash flows related to changes in deferred income taxes which is primarily due to certain adjustments that involve deferred state income taxes.

During the six months ended June 30, 2010, we had cash outflows from investing activities of $163.0 million, which were primarily due to the following:

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Cash outflows of $171.1 million for property, plant and equipment additions. These outflows include approximately $9.1 million related to the construction of our Wygen III power plant, which began commercial operations on April 1, 2010, approximately $40.6 million for construction of 180 MW of natural gas-fired electric generation at Colorado Electric, approximately $45.0 million for construction of 200 MW of natural gas-fired electric generation at Power Generation, approximately $11.6 million in oil and gas property maintenance capital and development drilling, and approximately $14.2 million for new transmission at the Electric Utilities;

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Cash inflows of $6.1 million of proceeds from the sale of gas utility assets at Nebraska Gas; and

- Cash outflows of $2.25 million for the acquisition of the coal marketing business at our Energy Marketing segment.

During the six months ended June 30, 2010, we had net cash outflows from financing activities of $29.8 million primarily resulting from:

- A $60.5 million inflow for net borrowings on the Revolving Credit Facility;
- A $28.2 million outflow for payments of cash dividends on common stock; and
- A $56.5 million outflow from long-term debt payments including $30.0 million for the Series AC bonds, $2.5 million for the Series Y bonds and $20.0 million for the Series Z bonds.

Dividends

Dividends paid on our common stock totaled $28.2 million for the six months ended June 30, 2010, or $0.72 per share. On July 28, 2010, our Board of Directors declared a quarterly dividend of $0.36 per share payable September 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 availability under our Revolving Credit Facility described below, as of June 30, 2010, we had approximately $64.0 million of cash unrestricted for operations.

$200 Million Debt Offering

On July 16, 2010, pursuant to a public offering, we issued a $200 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. We received proceeds of $198.7 million, net of underwriting fees. Proceeds were used to pay down a portion of borrowings on our Revolving Credit Facility and reduce issued letters of credit.

Revolving Credit Facility

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. The facility contains a commitment fee to be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.5%. The facility contains an accordion feature which allows us to increase the capacity of the facility to $600.0 million. Deferred financing costs of $4.6 million were capitalized and are being amortized over the three-year term of the facility.

At June 30, 2010, we had borrowings of $225.0 million and letters of credit outstanding of $36.5 million on our Revolving Credit Facility. Available capacity remaining on our Revolving Credit Facility was approximately $238.5 million at June 30, 2010.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintenance of 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.

Our consolidated net worth was $1,082.4 million at June 30, 2010, which was approximately $246.1 million in excess of the net worth we were required to maintain under the credit facility. At June 30, 2010, our long-term debt ratio was 47.8%, our total debt leverage ratio (long-term debt and short-term debt) was 53.0%, and our recourse leverage ratio was approximately 54.6%.

Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year $250.0 million committed credit facility. The facility includes a $100 million accordion feature which allows us, with the consent of the administrative agent, 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), Credit Agricole, 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%.

At June 30, 2010, $141.4 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

As a result of contractual positions acquired with the June 1, 2010 coal marketing business acquisition (see Note 20 of the Notes to the Condensed Consolidated Financial Statements), Enserco was temporarily not in compliance on one of the non-financial covenants to the Enserco Credit Facility. The Enserco Credit Facility limited the net fixed price volume of coal to 1.0 million tons. As of June 30, 2010, Enserco was above that limit. In July, the participating banks waived this covenant violation and increased the permitted net fixed price volume of coal allowed to 2.25 million tons for July 2010 and 2.0 million tons thereafter.

Black Hills Power

In February 2010, the Black Hills Power Series AC bonds matured. These bonds 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 principal balance of $2.5 million plus accrued interest and an early redemption premium of 2.618%.

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 in 2021. A total of $21.8 million was paid on June 1, 2010, which included the principal balance of $20.0 million plus 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 June 30, 2010, the restricted net assets at our Electric and Gas Utilities were approximately $164.0 million.

Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, Enserco may be restricted from making dividend payments to its parent company. The restricted net assets at June 30, 2010 at Enserco were $78.7 million compared to $205.8 million at December 31, 2009. Improved covenants under the new Enserco Credit Facility allowed for a reduction in capital investments in Enserco of more than $40 million.

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

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 agreements and restrictions imposed by federal and state regulatory authorities.

We have substantial capital expenditures remaining in 2010 and in 2011, which are primarily due to the construction of additional utility and IPP 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 may complete an additional long-term senior unsecured debt financing at the holding company level in 2010 or 2011. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%. We may also intend to complete a portion of the permanent financing through the issuance of common stock in order 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 these swaps are recorded within the income statement. For the three and six months ended June 30, 2010, respectively, we recorded a $24.9 million and $28.0 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 $66.7 million at June 30, 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 hedge interest rate exposure for periods to 2018 and 2028 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 6.5 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 $23.9 million at June 30, 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.

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 June 30, 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, as of June 30, 2010, Black Hills Power's first mortgage bonds were rated as follows:

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

* In July 2010, Moody's and S&P published updated credit reviews on Black Hills Corp., leaving unchanged our senior unsecured credit rating of Baa3 and BBB-, respectively, and leaving unchanged stable ratings outlooks.
** In July 2010, S&P upgraded the senior secured debt rating for Black Hills Power from BBB to BBB+.

Capital Requirements

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

	Six Months Ended June 30, 2010 Expenditures	Total 2010 Planned Expenditures
Utilities:		
Electric Utilities (1) (2) (3)	$ 89,295	$ 277,360
Gas Utilities	14,601	56,480
Non-regulated Energy:		
Oil and Gas(4)	12,579	38,320
Power Generation (5)	46,288	86,300
Coal Mining	5,879	16,540
Energy Marketing (6)	217	2,400
Corporate	9,891	—
	$ 178,750	$ 477,400

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(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.

(2) Electric Utilities planned capital expenditures include approximately

$34.3 million for transmission projects in 2010 (excluding transmission related to the 180 MW power plant at Colorado Electric) of which $14.2 million was spent in the first six months 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. The total construction cost is expected to be approximately $250 million to $260 million to be completed by the end of 2011. We expect to spend capital including transmission of $142.3 million in 2010 particularly related to the

commitment to purchase the turbine generators from GE. We spent $42.0 million during the first six months of 2010, leaving $100.3 million to be spent in the remainder of 2010.

(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. Continued low 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 $44.7 million during the first six months of 2010, leaving $35.3 million to be spent in the remainder of 2010.

(6) 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.

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

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment decreased $11.1 million from $97.7 million at December 31, 2009 to $86.6 million at June 30, 2010. Approximately $53.4 million of the firm transportation and storage fee obligations relate to the 2010-2012 period with the remaining occurring thereafter.

Plans to construct a 180 MW power generation facility by our Colorado Electric utility and plans to construct a 200 MW power generation facility at our Power Generation segment are progressing. Cost of construction is expected to be approximately $250 million to $260 million for Colorado Electric and $240 million to $265 million for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011. As our plans progress, we are in the process of procuring or have procured contracts for the turbines, building construction and labor. As of June 30, 2010, committed contracts for purchased equipment and construction were 100% and 44 % complete, respectively, for the Colorado Electric utility and 79% and 38%, respectively, for the Power Generation segment.

Guarantees

Except as noted below, there have been no new guarantees provided from those previously disclosed in Note 20 to our Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

We issued a guarantee for $6.0 million for a payment obligation arising from a contract to construct and purchase a new office building by Black Hills Utility Holdings. The office building is a 36,000 square foot office building located in Papillion, Nebraska. The guarantee will expire upon purchase of the building which is expected to be completed in 2011.

Black Hills Electric Generation issued a guarantee to the City of Pueblo, Colorado for the lesser of (a) the guaranteed obligations under the Annexation Agreement or (b) $10.0 million for the obligations of Colorado IPP relating to the construction of the 200 MW generation facility currently under construction. The guarantee will continue in force until December 31, 2011 and the current obligations do not exceed $2.9 million.

On July 22,2 2010, we issued a guarantee to Colorado Interstate Gas Company for $9.3 million for payment obligations of Black Hills Utility Holdings, Inc. related to natural gas transportation storage and services agreements. The guarantee expires July 31, 2011.

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 effect on our financial statements.

FORWARD-LOOKING INFORMATION

This report contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A. of our 2009 Annual Report on Form 10-K, Part II, Item 1A of this quarterly report on Form 10-Q, and other reports that we file with the SEC from time to time, and the following:

- We 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 $30.1 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 creating 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. We have a mechanism in South Dakota, Colorado, Wyoming and Montana for our electric utilities that serves a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer.

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

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

	June 30, 2010	December 31, 2009
Net derivative liabilities	$ (6,045)	$ (1,511)
Cash collateral	9,551	3,789
	$ 3,506	$ 2,278

Non Regulated Trading Activities

The following table provides a reconciliation of Energy Marketing activity in our natural gas, crude oil and coal 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 six months ended June 30, 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	(10,272)	
Unrealized gain (loss) on new positions entered during the period and still existing at June 30, 2010	17,082	
Realized (gain) loss on positions that existed at December 31, 2009 and were settled during the period	(1,266)	
Change in cash collateral	(2,728)	
Unrealized gain (loss) on positions that existed at December 31, 2009 and still exist at June 30, 2010	914	
Total fair value of energy marketing positions at June 30, 2010	$ 23,251	(a)

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(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):

	June 30, 2010	March 31, 2010	December 31, 2009
Net derivative assets	$ 31,720	$ 25,634	$ 17,084
Cash collateral	—	171	2,728
Market adjustment recorded in material, supplies and fuel	(8,469)	(11,039)	(291)
Total fair value of energy marketing positions marked-to-market	$ 23,251	$ 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	$ —	$ —	$ —
Level 1	—	—	—
Level 2	25,859	4,950	30,809
Level 3	168	743	911
Market value adjustment for inventory (see footnote (a) above)	(8,469)	—	(8,469)
Total fair value of our energy marketing positions	$ 17,558	$ 5,693	$ 23,251

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative

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under accounting for derivatives and hedging. Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas, crude oil and coal marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting standards for derivatives generally do not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our 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 June 30, 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)	$ 23,251	
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	(13,955	)
Fair value of all forward positions (non-GAAP)	9,296	
Cash collateral included in GAAP marked-to-market fair value	—	
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$ 9,296	

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

Except as discussed above, there have been no material changes in market risk from those reported in our 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.

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	8/20/2008	Swap	07/10 - 09/10	5,000	$ 7.74
AECO	8/20/2008	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	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	1/26/2009	Swap	07/10 - 09/10	2,000	$ 4.47
CIG	1/26/2009	Swap	10/10 - 12/10	2,000	$ 4.68
CIG	1/26/2009	Swap	01/11 - 03/11	2,000	$ 6.00
NWR	1/26/2009	Swap	01/11 - 03/11	2,000	$ 6.05
San Juan El Paso	1/26/2009	Swap	01/11 - 03/11	5,000	$ 6.38
San Juan El Paso	2/13/2009	Swap	01/11 - 03/11	2,500	$ 6.16
San Juan El Paso	2/13/2009	Swap	10/10 - 12/10	3,000	$ 5.35
NWR	2/13/2009	Swap		1,000	$ 4.20

			04/10 - 12/10		
AECO	3/4/2009	Swap	01/11 - 03/11	1,000	$ 5.95
NWR	3/4/2009	Swap	07/10 - 09/10	1,000	$ 4.12
NWR	3/4/2009	Swap	10/10 - 12/10	1,000	$ 4.55
San Juan El Paso	6/2/2009	Swap	04/11 - 06/11	5,000	$ 5.99
AECO	6/2/2009	Swap	04/11 - 06/11	800	$ 5.89
NWR	6/2/2009	Swap	04/11 - 06/11	1,500	$ 5.54
San Juan El Paso	6/25/2009	Swap	04/11 - 06/11	2,500	$ 5.55
CIG	6/25/2009	Swap	04/11 - 06/11	1,750	$ 5.33
CIG	9/2/2009	Swap	07/11 - 09/11	500	$ 5.32
NWR	9/2/2009	Swap	07/11 - 09/11	500	$ 5.32
San Juan El Paso	9/2/2009	Swap	07/11 - 09/11	2,500	$ 5.54
CIG	9/25/2009	Swap	07/11 - 09/11	500	$ 5.59
NWR	9/25/2009	Swap	07/11 - 09/11	1,000	$ 5.59
AECO	9/25/2009	Swap	07/11 - 09/11	500	$ 5.76
San Juan El Paso	9/25/2009	Swap	07/11 -	5,000	$ 5.91

			09/11		
San Juan El Paso	10/9/2009	Swap	07/10 - 09/10	1,000	$ 5.65
San Juan El Paso	10/9/2009	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	1/8/2010	Swap	1/12 - 3/12	2,500	$ 6.38

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
NWR	1/8/2010	Swap	01/12 - 03/12	1,500	$ 6.47
AECO	1/8/2010	Swap	01/12 - 03/12	500	$ 6.32
CIG	1/8/2010	Swap	01/12 - 03/12	1,500	$ 6.43
San Juan El Paso	1/25/2010	Swap	1/12 - 3/12	5,000	$ 6.44
San Juan El Paso	3/19/2010	Swap	7/11 - 9/11	500	$ 5.19
San Juan El Paso	3/19/2010	Swap	4/12 - 6/12	7,000	$ 5.27
CIG	3/19/2010	Swap	4/12 - 6/12	1,500	$ 5.17
NWR	3/19/2010	Swap	4/12 - 6/12	1,500	$ 5.20
AECO	3/19/2010	Swap	4/12 - 6/12	250	$ 5.15
San Juan El Paso	6/28/2010	Swap	7/12 - 9/12	3,500	$ 5.19
NWR	6/28/2010	Swap	7/12 - 9/12	1,500	$ 5.01
CIG	6/28/2010	Swap	7/12 - 9/12	1,500	$ 4.98

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	7/16/2008	Swap	07/10 - 09/10	5,000	$ 134.90
NYMEX	8/20/2008	Put	07/10 - 09/10	5,000	$ 90.00
NYMEX	9/3/2008	Put	07/10 - 09/10	5,000	$ 90.00
NYMEX	10/24/2008	Put		5,000	$ 60.00

			07/10 - 09/10		
NYMEX	12/5/2008	Swap	10/10 - 12/10	5,000	$ 65.20
NYMEX	1/26/2009	Swap	10/10 - 12/10	5,000	$ 60.15
NYMEX	1/26/2009	Swap	01/11 - 03/11	5,000	$ 60.90
NYMEX	2/13/2009	Swap	01/11 - 03/11	5,000	$ 60.05
NYMEX	3/4/2009	Swap	10/10 - 12/10	5,000	$ 55.80
NYMEX	3/4/2009	Swap	01/11 - 03/11	5,000	$ 57.00
NYMEX	4/8/2009	Swap	04/11 - 06/11	5,000	$ 68.80
NYMEX	4/23/2009	Swap	04/11 - 06/11	5,000	$ 65.10
NYMEX	6/2/2009	Swap	10/10 - 12/10	5,000	$ 74.30
NYMEX	6/2/2009	Swap	01/11 - 03/11	5,000	$ 75.05
NYMEX	6/2/2009	Swap	04/11 - 06/11	5,000	$ 75.86
NYMEX	6/4/2009	Put	04/11 - 06/11	5,000	$ 67.00
NYMEX	9/2/2009	Swap	07/11 - 09/11	5,000	$ 75.10
NYMEX	9/2/2009	Put	07/11 - 09/11	5,000	$ 63.00
NYMEX	9/29/2009	Swap	07/11 -	5,000	$ 74.00

			09/11		
NYMEX	10/6/2009	Put	07/11 - 09/11	5,000	$ 65.00
NYMEX	10/9/2009	Swap	10/11 - 12/11	5,000	$ 79.35
NYMEX	10/23/2009	Put	10/11 - 12/11	5,000	$ 75.00
NYMEX	11/19/2009	Swap	04/11 - 06/11	1,000	$ 85.35
NYMEX	11/19/2009	Swap	07/11 - 09/11	1,500	$ 85.95
NYMEX	11/19/2009	Swap	10/11 - 12/11	5,000	$ 87.50
NYMEX	1/8/2010	Swap	07/10 - 09/10	5,000	$ 85.60
NYMEX	1/8/2010	Swap	10/10 - 12/10	5,000	$ 86.88

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	1/8/2010	Put	10/11 - 12/11	6,000	$ 75.00
NYMEX	1/8/2010	Put	01/12 - 03/12	5,000	$ 75.00
NYMEX	1/25/2010	Swap	01/12 - 03/12	5,000	$ 83.30
NYMEX	2/26/2010	Swap	01/12 - 03/12	5,000	$ 83.80
NYMEX	3/19/2010	Swap	01/12 - 03/12	5,000	$ 83.80
NYMEX	3/19/2010	Swap	04/12 - 06/12	5,000	$ 84.00
NYMEX	3/31/2010	Put	04/12 - 06/12	5,000	$ 75.00
NYMEX	5/13/2010	Swap	04/12 - 06/12	5,000	$ 87.85
NYMEX	6/28/2010	Swap	07/12 - 09/12	5,000	$ 83.80

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 June 30, 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 June 30, 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, there are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2009.

Municipal governments may seek to limit or deny franchise privileges.
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.

Derivatives regulations included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.
In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") was passed by Congress and signed into law. The Act contains significant derivatives regulations, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as "margin") for such transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. The Act requires the CFTC to promulgate rules to define these terms, however we do not yet know the rules that the CFTC will actually promulgate nor the definitions will apply to us.

We use crude oil and natural gas derivative instruments in conjunction with our Energy Marketing activities and to hedge a portion of our expected oil and gas production. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. Depending on the regulations adopted by the CFTC, we could be required to post additional collateral with our dealer counterparties for our commitments and interest rate derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

ITEM 2.
Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans for Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2010 - April 30, 2010	—	$ —	—	—
May 1, 2010 - May 31, 2010	62	$ 33.26	—	—
June 1, 2010 - June 30, 2010	—	$ —	—	—
Total	62	$ 33.26	—	—

(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Omnibus Incentive Plan for the payment of taxes associated with the vesting of shares of Restricted Stock.

ITEM 6.
Exhibits

Exhibit 4	Third Supplemental Indenture dated as of July 16, 2010, between the Company and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4 to the Company's Form 8-K filed on July 15, 2010 and incorporated by reference herein).
Exhibit 10.1	Credit Agreement dated April 15, 2010 among Black Hills Corporation, as borrower, The Royal Bank of Scotland, Plc, as administrative agent for the banks under the Credit Agreement, and as a Bank and the other Banks party thereto filed as Exhibit 10.2 to the Company's Form 10-Q filed May 7, 2010 and incorporated by reference herein.
Exhibit 10.2	Independent Contractor Agreement dated May 3, 2010, between Black Hills Corporation and Lone Mountain Investments, Inc.
Exhibit 10.3	Indemnification Agreement dated as of May 3, 2010, between Black Hills Corporation and John B. Vering.
Exhibit 10.4	Joinder Agreement dated May 28, 2010 to the Third Amended and Restated Credit Agreement dated as of May 8, 2009, among Enserco Energy Inc., the borrower, BNP Paribas, as administrative agent, and Credit Agricole Corporate and Investment Bank (filed as Exhibit 10.1 to the Company's Form 8-K filed on June 3, 2010 and incorporated by reference herein).
Exhibit 10.5	Third Amendment to Third Amended and Restated Credit Agreement effective May 7, 2010, among Enserco Energy Inc., the borrower, Fortis Capital Corp., Societe Generale, as an issuing bank, a bank and the syndication agent, BNP Paribas, as an issuing bank, a bank, successor administrative agent and collateral agent and the documentation agent, and each of the other financial institutions which are parties thereto (filed as Exhibit 10 to the Company's Form 8-K filed on May 13, 2010 and incorporated by reference herein).
Exhibit 10.6	Fourth Amendment to Third Amended and Restated Credit Agreement effective May 28, 2010, among Enserco Energy Inc., the borrower, BNP Paribas, as administrative agent, collateral agent and the documentation agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent, and each of the other financial institutions which are parties thereto (filed as Exhibit 10.2 to the Company's Form 8-K filed on June 3, 2010 and incorporated by reference herein).
Exhibit 10.7	Fifth Amendment to Third Amendment and Restated Credit Agreement effective July 12, 2010, among Enserco Energy, Inc., as borrower, BNP Paribas, as administrative agent, collateral agent and the document agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent,

	and each of the other financial institutions which are parties thereto (filed as Exhibit 10 to the Company's Form 8-K filed on July 13, 2010 and incorporated by reference herein).
Exhibit 10.8	Second Amendment to the 2005 Omnibus Incentive Plan (filed as Exhibit 10 to the Company's Form 8-K filed on May 26, 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.
Exhibit 101	Financials for XBRL Format

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

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

Dated: August 6,
2010

EXHIBIT INDEX

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Exhibit 10.2	Independent Contractor Agreement dated May 3, 2010, between Black Hills Corporation and Lone Mountain Investments, Inc.
Exhibit 10.3	Indemnification Agreement dated as of May 3, 2010, between Black Hills Corporation and John B. Vering.
Exhibit 10.4	Joinder Agreement dated May 28, 2010 to the Third Amended and Restated Credit Agreement dated as of May 8, 2009, among Enserco Energy Inc., the borrower, BNP Paribas, as administrative agent, and Credit Agricole Corporate and Investment Bank (filed as Exhibit 10.1 to the Company's Form 8-K filed on June 3, 2010 and incorporated by reference herein).
Exhibit 10.5	Third Amendment to Third Amended and Restated Credit Agreement effective May 7, 2010, among Enserco Energy Inc., the borrower, Fortis Capital Corp., Societe Generale, as an issuing bank, a bank and the syndication agent, BNP Paribas, as an issuing bank, a bank, successor administrative agent and collateral agent and the documentation agent, and each of the other financial institutions which are parties thereto (filed as Exhibit 10 to the Company's Form 8-K filed on May 13, 2010 and incorporated by reference herein).
Exhibit 10.6	Fourth Amendment to Third Amended and Restated Credit Agreement effective May 28, 2010, among Enserco Energy Inc., the borrower, BNP Paribas, as administrative agent, collateral agent and the documentation agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent, and each of the other financial institutions which are parties thereto (filed as Exhibit 10.2 to the Company's Form 8-K filed on June 3, 2010 and incorporated by reference herein).
Exhibit 10.7	Fifth Amendment to Third Amendment and Restated Credit Agreement effective July 12, 2010, among Enserco Energy, Inc., as borrower, BNP Paribas, as administrative agent, collateral agent and the document agent, as an issuing bank, and a bank, Societe Generale, as an issuing bank, a bank and the syndication agent, and each of the other financial institutions which are parties thereto (filed as Exhibit 10 to the Company's Form 8-K filed on July 13, 2010 and incorporated by reference herein).

Exhibit 10.8	Second Amendment to the 2005 Omnibus Incentive Plan (filed as Exhibit 10 to the Company's Form 8-K filed on May 26, 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.
Exhibit 101	Financials for XBRL Format