BLACK HILLS CORP /SD/
Form 10-Q
November 09, 2009

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 September 30, 2009.

OR

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

Commission File Number 001-31303

Black Hills Corporation

Incorporated in South Dakota IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number (605) 721-1700

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes o No o

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

Large accelerated filer	x	Accelerated filer	o
Non-accelerated filer	o		o

Smaller reporting company

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

Yes 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 October 30, 2009
Common stock, $1.00 par value	38,866,236 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for the Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of Aquila's regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa
Bbl	Barrel
Bcf	Billions cubic feet
Bcfe	Billion cubic feet equivalents
BHCRPP	Black Hills Corporation Risk Policies and Procedures
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings, including the gas and electric utility properties acquired from Aquila
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company that was formerly known as Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Service Company	Black Hills Service Company, a direct wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company formed to acquire and own the utility properties acquired from Aquila, all which are now doing business as Black Hills Energy
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned

	subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
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, formed to hold the Colorado electric utility properties acquired from Aquila

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, formed to hold the Colorado gas utility properties acquired from Aquila
Corporate Credit Facility	Our unsecured $525 million revolving line of credit
CPUC	Colorado Public Utilities Commission
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
EPA	Environmental Protection Agency
EPS	Earnings per share
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GE	GE Packaged Power, Inc.
GHG	Greenhouse gases
GSRS	Gas Safety and Reliability Surcharge
Hastings	Hastings Funds Management Ltd
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
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, formed to hold the Iowa gas utility properties acquired from Aquila
IPP	Independent Power Production
IPP Transaction	Our July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Kansas gas utility properties acquired from Aquila
KCC	Kansas Corporation Commission
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand cubic feet
Mcfe	One thousand 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

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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, formed to hold the Nebraska gas utility properties acquired from Aquila
NPA	Nebraska Public Advocate
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Silver Sage	Silver Sage Windpower LLC, a subsidiary of Duke Energy Corporation
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

ACCOUNTING STANDARDS

ASC	Accounting Standards Codification
ASC 105	ASC 105, "FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Standard No. 162
ASC 260	ASC 260, "Earnings Per Share"
ASC 715	ASC 715, "Compensation – Retirement Benefits"
ASC 805	ASC 805, "Business Combinations"
ASC 810	ASC 810, "Consolidations"
ASC 810-10-15	ASC 810-10-15, "Consolidation of Variable Interest Entities"
ASC 815	ASC 815, "Derivatives and Hedging"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASC 825	ASC 825, "Financial Instruments"
ASC 855	ASC 855, "Subsequent Events"
ASC 940-325-S99	ASC 940-325-S99, "SEC Materials"
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FSP	FASB Staff Position
FSP EITF 03-6-1	FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities"
FSP FAS 107-1	FSP FAS 107-1, "Interim Disclosure About Fair Value of Financial Instruments"
FSP FAS 132(R)-1	FSP FAS 132(R)-1, "Employer's Disclosures about Pensions and Other Postretirement Benefits" (Revised)
FSP FAS 157-4	FSP FAS 157-4, "Determining Whether a Market is Not Active and a Transaction is Not Distressed"
SEC Release No. 33-8995	SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting"
SFAS	Statement of Financial Accounting Standards
SFAS 141(R)	SFAS 141(R), "Business Combinations"
SFAS 157	SFAS 157, "Fair Value Measurements"
SFAS 160	SFAS 160, "Non-controlling Interest in Consolidated Financial Statements – an amendment of ARB No. 51"
SFAS 161	SFAS 161, "Disclosure about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133"
SFAS 165	SFAS 165, "Subsequent Events"
SFAS 167	SFAS 167, "Amendment to FASB Interpretation No. 46(R)"
SFAS 168	SFAS 168, "FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Standard No. 162"

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands, except per share amounts)			
Operating revenues	$ 225,799	$ 291,892	$ 921,090	$ 598,015
Operating expenses:				
Fuel and purchased power	94,120	131,300	467,309	230,643
Operations and maintenance	35,431	34,477	115,226	80,762
Gain on sale of assets	—	—	(25,971)	—
Administrative and general	38,344	40,993	117,817	90,273
Depreciation, depletion and amortization	29,824	30,825	92,535	70,999
Taxes, other than income taxes	11,171	11,609	34,680	31,590
Impairment of long-lived assets	—	—	43,301	—
	208,890	249,204	844,897	504,267
Operating income	16,909	42,688	76,193	93,748
Other income (expense):				
Interest expense	(20,691)	(16,402)	(62,930)	(35,160)
Interest rate swap – unrealized (loss) gain	(8,694)	—	37,775	—
Interest income	327	628	1,184	1,427
Allowance for funds used during construction – equity	2,598	1,390	5,284	2,287
Other income, net	2,142	171	3,779	573
	(24,318)	(14,213)	(14,908)	(30,873)
(Loss) income from continuing operations before equity in earnings of unconsolidated subsidiaries and income taxes	(7,409)	28,475	61,285	62,875
Equity in earnings of unconsolidated subsidiaries	119	1,359	1,368	3,656
	3,437	(10,312)	(16,300)	(21,989)

Income tax benefit (expense)				
(Loss) income from continuing operations	(3,853)	19,522	46,353	44,542
Income from discontinued operations, net of taxes	1,673	145,389	2,439	159,486
Net (loss) income	(2,180)	164,911	48,792	204,028
Net loss attributable to non-controlling interest	—	—	—	(130)
Net (loss) income available for common stock	$ (2,180)	$ 164,911	$ 48,792	$ 203,898
Weighted average common shares outstanding:				
Basic	38,643	38,307	38,584	38,145
Diluted	38,643	38,425	38,646	38,430
Earnings (loss) per share:				
Basic–				
Continuing operations	$ (0.10)	$ 0.51	$ 1.20	$ 1.16
Discontinued operations	0.04	3.79	0.06	4.18
Total	$ (0.06)	$ 4.30	$ 1.26	$ 5.34
Diluted–				
Continuing operations	$ (0.10)	$ 0.51	$ 1.20	$ 1.16
Discontinued operations	0.04	3.78	0.06	4.15
Total	$ (0.06)	$ 4.29	$ 1.26	$ 5.31
Dividends declared per share of common stock	$ 0.355	$ 0.350	$ 1.065	$ 1.050

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	September 30, 2009	December 31, 2008	September 30, 2008
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$137,681	$168,491	$152,457
Restricted cash	6	—	5,514
Short-term investments	—	—	6,310
Receivables, net	208,563	357,404	227,862
Materials, supplies and fuel	99,952	118,021	173,734
Derivative assets	56,951	73,068	84,758
Income tax receivable, net	—	20,269	—
Deferred income taxes	13,221	10,244	—
Regulatory assets	12,775	35,390	17,360
Other current assets	31,565	16,380	15,064
Assets of discontinued operations	—	246	322
	560,714	799,513	683,381
Investments	19,462	22,764	21,911
Property, plant and equipment	2,891,102	2,705,492	2,615,627
Less accumulated depreciation and depletion	(795,378)	(683,332)	(566,191)
	2,095,724	2,022,160	2,049,436
Other assets:			
Goodwill	353,734	359,290	400,959
Intangible assets, net	4,725	4,884	—
Derivative assets	5,438	9,799	1,500
Regulatory assets	120,677	143,705	51,122
Other	7,861	17,774	18,390
	492,435	535,452	471,971
	$3,168,335	$3,379,889	$3,226,699
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$184,208	$288,907	$234,647
Accrued liabilities	150,042	134,940	140,981
Derivative liabilities	68,634	118,657	62,409
Deferred income taxes	—	—	592
Accrued income taxes, net	15,734	—	48,360
Regulatory liabilities	30,120	5,203	3,787
Notes payable	350,500	703,800	627,800
Current maturities of long-term debt	32,091	2,078	2,074
Liabilities of discontinued operations	—	88	124
	831,329	1,253,673	1,120,774
Long-term debt, net of current maturities	719,215	501,252	501,277

Deferred credits and other liabilities:			
Deferred income taxes	228,715	223,607	240,654
Derivative liabilities	27,824	22,025	6,792
Regulatory liabilities	40,168	38,456	37,824
Benefit plan liabilities	135,027	159,034	44,465
Other	123,527	131,306	125,552
	555,261	574,428	455,287
Stockholders' equity:			
Common stock equity –			
Common stock $1 par value; 100,000,000 shares authorized;			
Issued 38,872,925; 38,676,054 and 38,490,315 shares, respectively	38,873	38,676	38,490
Additional paid-in capital	588,556	584,582	580,601
Retained earnings	454,907	447,453	561,102
Treasury stock at cost – 7,605; 40,183 and 40,059 shares, respectively	(197)	(1,392)	(1,419)
Accumulated other comprehensive loss	(19,609)	(18,783)	(29,545)
Total common stockholders' equity	1,062,530	1,050,536	1,149,229
Non-controlling interest in subsidiaries	—	—	132
Total equity	1,062,530	1,050,536	1,149,361
	$3,168,335	$3,379,889	$3,226,699

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

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)	
Operating activities:		
Net income	$48,792	$204,028
Income from discontinued operations, net of taxes	(2,439)	(159,486)
Income from continuing operations	46,353	44,542
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	92,535	70,999
Impairment of long-lived assets	43,301	—
Derivative fair value adjustments	19,647	(26,853)
Gain on sale of operating assets	(25,971)	—
Unrealized mark-to-market gain on interest rate swaps	(37,775)	—
Deferred income taxes	5,164	76,546
Distributed (undistributed) earnings of associated companies	3,424	(1,988)
Allowance for funds used during construction – equity	(5,284)	(2,287)
Other non-cash adjustments	(4,782)	(4,295)
Change in operating assets and liabilities:		
Materials, supplies and fuel, net of market adjustments	23,210	(47,382)
Accounts receivable and other current assets	157,118	111,595
Accounts payable and other current liabilities	(101,902)	(118,369)
Regulatory assets and liabilities	54,272	(30,204)
Other operating activities	(939)	(10,403)
Net cash provided by operating activities of continuing operations	268,371	61,901
Net cash provided by operating activities of discontinued operations	2,556	18,184
Net cash provided by operating activities	270,927	80,085
Investing activities:		
Property, plant and equipment additions	(245,114)	(219,350)
Proceeds from sale of business operations	—	835,316
Proceeds from sale of ownership interest in plants	84,661	—
Payment for acquisition of net assets, net of cash acquired	—	(937,606)
Working capital adjustment of purchase price allocation on Aquila assets	7,098	—
Purchase of short-term investments	—	(6,525)
Other investing activities	1,933	(698)
Net cash used in investing activities of continuing operations	(151,422)	(328,863)
Net cash used in investing activities of discontinued operations	—	(28,966)
Net cash used in investing activities	(151,422)	(357,829)
Financing activities:		
Dividends paid	(41,338)	(40,189)
Common stock issued	2,338	2,611
(Decrease) increase in short-term borrowings, net	(353,300)	590,800

Long-term debt – issuances	248,500	—
Long-term debt – repayments	(2,024)	(130,276)
Other financing activities	(4,532)	(72)
Net cash (used in) provided by financing activities of continuing operations	(150,356)	422,874
Net cash used in financing activities of discontinued operations	—	(73,928)
Net cash (used in) provided by financing activities	(150,356)	348,946
(Decrease) increase in cash and cash equivalents	(30,851)	71,202
Cash and cash equivalents:		
Beginning of period	168,532 (a)	81,255 (b)
End of period	$137,681	$152,457
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	$31,202	$25,549
Cash paid during the period for-		
Interest (net of amounts capitalized)	$50,311	$29,748
Income taxes (refunded) paid	$(23,311)	$2,984

(a) Includes less than $0.1 million of cash included in the assets of discontinued operations.
(b) Includes approximately $4.4 million of cash included in the assets of discontinued operations.

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 2008 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," "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 2008 Annual Report on Form 10-K filed with the SEC. These financial statements include consideration of events through November 6, 2009.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying condensed quarterly financial statements reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of the September 30, 2009, December 31, 2008 and September 30, 2008 financial information and are of a normal recurring nature. Certain reclassifications have been made to prior period presentations to conform to the current year presentation but have no affect over the results of the prior period numbers. 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 nine months ended September 30, 2009, and our financial condition as of September 30, 2009 and December 31, 2008, 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.

On July 11, 2008, we completed the sale of seven of our IPP plants. Amounts associated with the IPP plants divested in the IPP Transaction have been reclassified as discontinued operations for the quarter ended September 30, 2008. See Note 19 for additional information.

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and regulated gas utilities in Colorado, Kansas, Nebraska and Iowa from Aquila. Effective as of that date, the assets and liabilities, results of operations, and cash flows of the acquired utilities are included in our Condensed Consolidated Financial Statements. See Note 17 for additional information.

(2) RECENTLY ADOPTED ACCOUNTING STANDARDS

FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Standard No. 162, ASC 105 (SFAS 168)

On July 1, 2009, the FASB Accounting Standards CodificationTM became the source of authoritative GAAP recognized by the FASB to be applied by non-governmental entities. On the effective date of this Statement, the Codification superseded all then-existing non-SEC accounting and reporting standards. All other non-SEC accounting literature not included or grandfathered in the Codification became non-authoritative. This Statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009.

Following this Statement, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Task Force Abstracts. Instead, it will issue Accounting Standards Updates. The FASB will not consider Accounting Standards Updates as authoritative in their own right. Accounting Standards Updates will serve only to update the Codification, provide background information about the guidance, and provide the basis for conclusions on the change(s) in the Codification.

Business Combinations, ASC 805 (SFAS 141(R))

The ASC for Business Combinations requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date be measured at their fair values as of the acquisition date, with limited exceptions. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. If income tax liabilities are settled for an amount other than as previously recorded, the adjustment of any remaining liability would affect goodwill. If such liabilities are adjusted subsequent to December 31, 2008, such adjustments will affect expense including income tax expense in the period of adjustment. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. These requirements apply prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. Effective January 1, 2009, any impact a business combination will have on our consolidated financial statements will depend on the nature and magnitude of any future acquisitions we consummate and the resolution of certain tax contingencies.

Fair Value Measurements and Disclosures, ASC 820 (SFAS 157 and FSP FAS 157-4)

The ASC for Fair Value Measurements and Disclosures defines fair value, establish a framework for measuring fair value in GAAP and expand disclosures about fair value measurements. This does not expand the application of fair value accounting to any new circumstances, but applies the framework to other applicable GAAP that requires or permits fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy Marketing and Oil and Gas segments, interest rate swap instruments, and other miscellaneous derivatives.

On January 1, 2008, we discontinued our use of a “liquidity reserve” in valuing the total forward positions within our energy marketing portfolio. This impact was accounted for prospectively as a change in accounting estimate and resulted in a $1.2 million after-tax benefit that was recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Operating revenues on the accompanying Condensed Consolidated Statements of Income. Disclosures regarding the level of pricing observability associated with instruments carried at fair value are provided in Note 15.

Consolidation of Non-Controlling Interest, ASC 810 (SFAS 160)

The ASC for Consolidation of Non-Controlling Interest establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, changes in a parent's ownership interest, and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The ASC establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. These standards and disclosure requirements were effective January 1, 2009.

Non-controlling interest in the accompanying Condensed Consolidated Statements of Income and Balance Sheets represents the non-affiliated equity investors' interest in Wygen Funding LP, a Variable Interest Entity as defined by ASC 810. In June 2008, we purchased the non-controlling share. Presentation of a non-controlling interest that we held until June 2008 was retrospectively applied as required, and had an immaterial overall effect.

Derivative and Hedging Disclosures, ASC 815 (SFAS 161)

The ASC for Derivative and Hedging Disclosures requires enhanced disclosures about derivative and hedging activities and their affect on an entity's financial position, financial performance and cash flows. ASC 815 encourages, but does not require, disclosures for earlier periods presented for comparative purposes at initial adoption. Required disclosures for periods subsequent to January 1, 2009 are provided in Note 13 and Note 14.

Subsequent Events, ASC 855 (SFAS 165)

The ASC for Subsequent Events establishes general standards of accounting for and disclosures of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. These standards and disclosures were applied to our financial statements issued after June 15, 2009.

Financial Instruments, ASC 825 (FSP FAS 107-1)

The ASC for Financial Instruments requires public companies to provide more frequent disclosures about the fair value of their financial instruments for interim and annual periods ending after June 15, 2009. These disclosures are included in Note 15.

Earnings Per Share, ASC 260 (FSP EITF 03-6-1)

The ASC for Earnings per share states that unvested share-based payment awards that contain non-forfeitable rights to dividends are "participating securities" as defined and should be included in computing EPS using the two-class method. The two-class method is an earnings allocation method for computing EPS and determines EPS based on dividends declared on common stock and participating securities in any undistributed earnings. As of January 1, 2009, we prepared our current and prior period EPS computation in accordance with the guidance in ASC 260 and there was no impact on our EPS.

(3) RECENTLY ISSUED ACCOUNTING STANDARDS

SEC Release No. 33-8995

On December 29, 2008, the SEC issued Release No. 33-8995, amending the existing Regulation S-K and Regulation S-X requirements for reporting the quantity and value of oil and gas reserves 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 pricing used to determine reserves. Companies must use a 12-month average price. The average is calculated using unweighted average of the first-day-of-the-month price for each of the 12 months that make up the reporting period. The amendment is effective for annual reporting periods ending on December 31, 2009, and early adoption is prohibited. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

Consolidation of Variable Interest Entities, ASC 810-10-15 (SFAS 167)

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 will require 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. We are currently assessing the impact that the adoption of this standard will have on our financial condition, results of operations, and cash flows.

Compensation – Retirement Benefits, ASC 715 (FSP FAS 132(R)-1)

The ASC for Compensation – Retirement Benefits provides guidance on an employer’s disclosures about plan assets in a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of:

· How investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies;

· The major categories of plan assets;

· The input and valuation techniques used to measure the fair value of plan assets;

· The effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period; and

· Significant concentrations of risk within plan assets.

These disclosures are effective for fiscal years ending after December 15, 2009.

(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	September 30, 2009	December 31, 2008	September 30, 2008
Materials and supplies	$31,650	$32,580	$32,565
Fuel – Electric Utilities	7,234	10,058	11,497
Natural gas in storage – Gas Utilities	29,943	59,529	74,407
Gas and oil held by Energy Marketing*	31,125	15,854	55,265
Total materials, supplies and fuel	$99,952	$118,021	$173,734

* As of September 30, 2009, December 31, 2008 and September 30, 2008, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(1.3) million, $(9.4) million and $(15.1) million, respectively (see Note 13 for further discussion of Energy Marketing trading activities).

Gas and oil inventory held by Energy Marketing primarily consists of gas held in storage. Such gas is being held in inventory to capture the price differential between the time at which it was purchased and a subsequent sales date in the future. Natural gas volumes held as of September 30, 2009, December 31, 2008 and September 30, 2008 include 8.2 Bcf, 3.6 Bcf, and 7.9 Bcf. Crude oil volumes held as of September 30, 2009, December 31, 2008 and September 30, 2008 include 71,000 Bbl, 54,000 Bbl, and 64,000 Bbl, respectively.

Natural gas in storage at our Gas Utilities represents primarily gas purchased for use by our customers. The natural gas in storage fluctuates with the seasonality of our business and the commodity price of natural gas. Although volumes held in storage by us have varied due to season, there has been a notable price decrease during 2009 and 2008. Volumes held as of September 30, 2009, December 31, 2008 and September 30, 2009 include 8.6 Bcf, 7.3 Bcf and 8.6 Bcf, respectively.

(5) ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

Following is a summary of receivables (in thousands):

	September 30, 2009	December 31, 2008	September 30, 2008

Accounts receivable	$214,065	$364,155	$233,939
Less allowance for doubtful accounts	5,502	6,751	6,077
Net accounts receivable	$208,563	$357,404	$227,862

(6) NOTES PAYABLE AND LONG-TERM DEBT

Debt Offering

On May 14, 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds of $248.5 million, net of underwriting fees. Proceeds were used to pay down the Acquisition Facility. Deferred financing costs related to the offering of $2.3 million were capitalized and will be amortized over the life of the debt. Amortization of these deferred financing costs is included in interest expense and for the three and nine months ended September 30, 2009 was approximately $0.1 million and $0.2 million, respectively.

Acquisition Facility

In May 2007, we entered into a senior unsecured $1 billion Acquisition Facility with ABN AMRO Bank N.V., as administrative agent, and other banks to fund the Aquila Transaction. On July 14, 2008, in conjunction with the completion of the purchase of the Aquila properties, we executed a single draw of $382.8 million under the Acquisition Facility. The loan was originally scheduled to mature on February 5, 2009. However, on December 18, 2008, we amended the facility to extend the maturity date to December 29, 2009. The Acquisition Facility was repaid in the second quarter of 2009 using: (1) net proceeds from the sale of a 25% ownership interest in the Wygen III plant of $30.2 million; (2) net proceeds from the $250 million public debt offering; and (3) $104.6 million from borrowings under the Corporate Credit Facility. Approximately $3.6 million of unamortized deferred financing costs were fully expensed in the second quarter of 2009 in conjunction with the repayment of this facility. Therefore, amortization of the deferred financing costs associated with this facility is included in Interest expense on the accompanying Condensed Consolidated Statements of Income and for the nine months ended September 30, 2009 was $4.8 million.

Corporate Credit Facility

Our consolidated net worth was $1,062.5 million at September 30, 2009, which was approximately $254.0 million in excess of the net worth we are required to maintain under the Corporate Credit Facility. At September 30, 2009, our long-term debt ratio was 40.4%, our total debt coverage leverage ratio (long-term debt and short-term debt) was 50.9%, and our recourse leverage ratio was approximately 55.2%. Our interest expense coverage ratio for the twelve month period ended September 30, 2009 was 3.7 to 1.0. We were in compliance with our covenants as of September 30, 2009.

Enserco Credit Facility

On May 8, 2009, Enserco entered into an agreement for a $240 million committed credit facility. Societe Generale, Fortis Capital Corp., and BNP Paribas were co-lead arranger banks. On May 27, 2009, Enserco entered into an agreement for an additional $60 million of commitments under the credit facility with three new participating banks: Calyon, Rabobank and RZB Finance. This credit facility expires on May 7, 2010 and is a borrowing base line of credit, which allows for the issuance of letters of credit and for borrowings. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds.

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At September 30, 2009, $71.7 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding. Deferred financing costs of $1.9 million were capitalized and are amortized over the life of the facility. Amortization of these deferred financing costs is included in interest expense and for the three and nine months ended September 30, 2009 was approximately $0.1 million and $0.9 million, respectively.

Industrial Development Revenue Bonds

Cheyenne Light completed a $17 million weekly variable rate refunding bond issuance on September 3, 2009. The new issue replaces existing debt and the bond credit support structure from an AMBAC Financial Group insurance policy to a direct-pay letter of credit issued by Wells Fargo Bank. Laramie County, Wyoming was the tax-exempt conduit issuer for this transaction. The bonds were issued in two series: a $10.0 million series maturing March 1, 2027 and a $7.0 million series maturing September 1, 2021. The principal amounts and maturity dates did not change from the original financing. The initial variable weekly rate was set at 0.4%. Excluding the letter of credit fees and other issuance costs, the current all-in rate is approximately 2.65%.

(7) GUARANTEES

Guarantees to GE

We issued two guarantees for up to $37.9 million each to GE for payment obligations arising from a contract to purchase two LMS100 natural gas turbine generators by Colorado Electric, which will be used in meeting a portion of the capacity and energy needs of our Colorado Electric customers. These are continuing guarantees which terminate upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated construction milestone dates with the final payment due October 27, 2010.

Surety Bonds Issued to MEAN

On January 20, 2009, we issued a surety bond for $9.2 million to MEAN to secure operating performance obligations related to the Wygen I ownership agreement. Black Hills Wyoming and MEAN entered into the ownership agreement when MEAN acquired a 23.5% ownership interest in the Wygen I plant. The surety bond and guarantees expire on December 31, 2009.

Enserco

We have guaranteed up to $7.0 million of the obligations of Enserco under an agency agreement whereby Enserco provides services to structure certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company. The guarantee expires in July 2010.

(8) EARNINGS PER SHARE

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

Period ended September 30, 2009	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
(Loss) income from continuing operations	$(3,853)		$46,353	
Basic earnings	(3,853)	38,643	46,353	38,584
Dilutive effect of:				
Restricted stock	—	—	—	60
Other	—	—	—	2
Diluted earnings	$(3,853)	38,643	$46,353	38,646

Period ended September 30, 2008	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$19,522		$44,542	
Basic earnings	19,522	38,307	44,542	38,145
Dilutive effect of:				
Stock options	—	42	—	62
Estimated contingent shares issuable for prior acquisition	—	—	—	132
Restricted stock	—	72	—	70
Other	—	4	—	21
Diluted earnings	$19,522	38,425	$44,542	38,430

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Options to purchase common stock	374	151	484	99

(9) OTHER COMPREHENSIVE INCOME

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008
Net (loss) income	$(2,180)	$164,911
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustments (net of tax of $(1,999))	3,671	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $5,670 and $(14,030), respectively)	(10,311)	25,824
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(1,948) and $(1,539), respectively)	3,446	2,761
Unrealized gain on available for sale securities (net of tax of $17 in 2008)	—	(32)
Comprehensive (loss) income attributable to Black Hills Corporation	$(5,374)	$193,464

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	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net income	$48,792	$204,028
Other comprehensive income (loss), net of tax:		
Minimum pension liability adjustment (net of tax of $(1,999))	3,671	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $8,598 and $6,449, respectively)	(15,106)	(11,951)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(6,008) and $(3,952), respectively)	10,609	7,071
Unrealized loss on available for sale securities (net of tax of $58)	—	(157)
Total comprehensive income	47,966	198,991
Comprehensive loss attributable to non-controlling interest	—	(130)
Comprehensive income attributable to Black Hills Corporation	$47,966	$198,861

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

	September 30, 2009	December 31, 2008	September 30, 2008
Derivatives designated as cash flow hedges	$(9,037)	$(4,522)	$(23,168)
Employee benefit plans	(10,456)	(14,127)	(6,115)
Amount from equity-method investees	(116)	(134)	(122)
Unrealized loss on available-for-sale securities	—	—	(140)
Total	$(19,609)	$(18,783)	$(29,545)

(10) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock, as reported in Note 10 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K.

Equity Compensation Plans

· We granted 78,136 target performance shares to certain officers and business unit leaders for the January 1, 2009 through December 31, 2011 performance period. Actual shares are not issued until the end of the Performance Plan period (December 31, 2011). 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, our stock price must also increase during the performance period. 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 $29.20 per share.

· We issued 47,331 shares of common stock under the 2008 short-term incentive compensation plan during the nine months ended September 30, 2009. Pre-tax compensation cost related to the award was approximately $1.6 million, which was accrued for in 2008.

· We granted 84,376 restricted common shares during the nine months ended September 30, 2009. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $2.3 million will be recognized over the three-year vesting period.

· 5,000 stock options were exercised during the nine months ended September 30, 2009 at a weighted-average exercise price of $24.06 per share providing $0.1 million of proceeds to the Company.

Total compensation expense recognized for all equity compensation plans for the three months ended September 30, 2009 and 2008 was $1.1 million and $0.3 million, respectively, and for the nine months ended September 30, 2009 and 2008 was $2.9 million and $1.0 million, respectively.

As of September 30, 2009, total unrecognized compensation expense related to non-vested stock awards was $5.8 million and is expected to be recognized over a weighted-average period of 2.0 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 111,753 new shares at a weighted-average price of $20.91 during the nine months ended September 30, 2009. At September 30, 2009, 327,562 shares of unissued common stock were available for future offering under the Plan.

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, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries.

Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of September 30, 2009, the restricted net assets at our Electric and Gas Utilities were approximately $79.2 million.

In August 2009, one of the covenants to the Enserco Credit Facility was amended to temporarily increase the allowable rolling twelve month Net Cumulative Loss as calculated on a Non-GAAP basis and temporarily restrict all dividends or loans to the Company. In addition to the borrowing base structure which requires Enserco to maintain certain levels of tangible net worth and net working capital, 100% of Enserco’s net assets are now restricted. The Company expects this to be the case through November 30, 2009. Therefore, upon review of these covenants at September 30, 2009, restricted net assets at Enserco total $214.3 million for this stand-alone Enserco Credit Facility.

(11) EMPLOYEE BENEFIT PLANS

We have three non-contributory defined benefit pension plans (“Plans”) and three Postretirement Healthcare Plans (“Healthcare 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.

Defined Benefit Pension Plans

In July 2009, the Board of Directors approved a resolution to freeze two of our Defined Benefit Pension Plans to new participants and to transfer certain existing participants to an age and service based defined contribution plan, effective January 1, 2010. The first plan covers employees of Black Hills Service Company, Black Hills Power, WRDC and BHEP and the second plan covers employees of Black Hills Energy. Plan assets and obligations were revalued July 31, 2009 in conjunction with the curtailment of these plans and we recognized a pre-tax curtailment expense of approximately $0.3 million in the three months ended September 30, 2009.

The following table sets forth the projected benefit obligation as of December 31, 2008 and July 31, 2009. The July 31, 2009 projected benefit obligation reflects the curtailment of the two plans and includes the Cheyenne Light pension plan projected benefit obligation as of its December 31, 2008 measurement date:

	Defined Benefit Pension Plans at July 31, 2009 (in thousands)
Change in benefit obligation:	
Projected benefit obligation at December 31, 2008	$242,545
Service cost	4,743
Interest cost	8,713
Actuarial loss	453
Amendments	20
Benefits paid	(5,159)
Benefits curtailed	(8,033)
Change in discount rate	(1,613)
Net increase (decrease)	(876)
Projected benefit obligation at July 31, 2009	$241,669

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Service cost	$1,877	$1,547	$5,736	$3,055
Interest cost	3,679	3,165	11,036	5,625
Expected return on plan assets	(3,638)	(3,644)	(10,553)	(6,790)
Prior service cost	25	41	108	123
Net loss	637	—	2,140	—
Curtailment expense	320	—	320	—
Net periodic benefit cost	$2,900	$1,109	$8,787	$2,013

We made a $0.5 million contribution to the Plans in the first quarter of 2009, a $3.9 million contribution to the Plans in the second quarter of 2009, and a $12.5 million contribution to the Plans during the third quarter of 2009. There are no additional contributions anticipated to be made to the Plans for 2009. We anticipate additional contributions totaling approximately $7.7 million in 2010.

Non-pension Defined Benefit Postretirement Healthcare Plans

Employees who are participants in our Healthcare Plans and who meet certain eligibility requirements are entitled to certain postretirement healthcare benefits.

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Service cost	$260	$226	$780	$476
Interest cost	542	503	1,626	937
Expected return on plan assets	(56)	(43)	(168)	(43)
Prior service benefit	(22)	—	(66)	—
Net transition obligation	15	15	45	45
Net gain	(8)	(20)	(24)	(60)
Net periodic benefit cost	$731	$681	$2,193	$1,355

We anticipate that we will make aggregate contributions to the Healthcare Plans for the 2009 and 2010 fiscal years of approximately $2.8 million and $3.0 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 and $0.3 million for the three and nine month periods ended September 30, 2009.

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Supplemental Non-qualified Defined Benefit Plans

Additionally, we have various supplemental retirement plans for key executives ("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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Service cost	$117	$112	$351	$336
Interest cost	344	311	1,032	933
Prior service cost	1	3	3	9
Net loss	147	142	441	426
Net periodic benefit cost	$609	$568	$1,827	$1,704

We anticipate that we will make aggregate contributions to the Supplemental Plans for the 2009 fiscal year of approximately $1.0 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 September 30, 2009, substantially all of our operations and assets are located within the United States.

The Utilities Group includes two reportable segments: Electric Utilities and Gas Utilities. We manage our electric and gas utility businesses predominantly by state; however, because our electric utilities and our gas utilities have similar economic characteristics, we aggregate our electric (and combination) utility businesses in the Electric Utilities reporting segment and our gas utility businesses in the Gas Utilities reporting segment. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. The natural gas operations within our combination utility, Cheyenne Light, have historically provided relatively stable gross margins and overall financial results. Periodic variances are therefore rarely expected to significantly impact the operating results for the Electric Utilities segment. Presentation of prior periods has been adjusted to reflect the combination of Black Hills Power and Cheyenne Light within the Electric Utilities segment. Gas Utilities, acquired on July 14, 2008, consists of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas.

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. Our Power Generation segment has also 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 and which are expected to be placed into service by December 31, 2011;

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

· Energy Marketing, which markets natural gas, crude oil and related services primarily in the western and central regions of the United States and Canada.

Segment information follows the same accounting policies as described in Note 1 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K. In accordance with accounting standards for regulated operations, intercompany fuel 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			
	September 30, 2009		September 30, 2008	
	External Operating Revenues	Inter-segment Operating Revenues	External Operating Revenues	Inter-segment Operating Revenues
Utilities:				
Electric Utilities	$ 128,943	$ 223	$ 136,644	$ 334
Gas Utilities	62,691	—	83,937	—
Non-regulated Energy:				
Oil and Gas	17,887	—	25,438	—
Power Generation	7,538	—	11,704	—
Coal Mining	8,284	6,903	8,103	7,928
Energy Marketing	(5,259)	—	19,196	—
Inter-segment eliminations	—	(1,411)	—	(1,392)
Total	$ 220,084	$ 5,715	$ 285,022	$ 6,870

	Nine Months Ended			
	September 30, 2009		September 30, 2008	
	External Operating Revenues	Inter-segment Operating Revenues	External Operating Revenues	Inter-segment Operating Revenues
Utilities:				
Electric Utilities	$384,607	$ 653	$329,512	$ 1,004
Gas Utilities	412,366	—	83,937	—
Non-regulated Energy:				
Oil and Gas	52,227	—	85,770	—
Power Generation	22,372	—	29,079	—
Coal Mining	23,967	19,115	23,979	17,946
Energy Marketing	9,299	—	30,465	—
Inter-segment eliminations	—	(3,516)	—	(3,677)
Total	$904,838	$ 16,252	$582,742	$ 15,273

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Income (loss) from continuing operations				
Utilities:				
Electric Utilities	$10,537	$10,765	$24,395	$30,485
Gas Utilities	(3,484)	(1,854)	14,223	(1,854)
Non-regulated Energy:				
Oil and Gas	(149)	1,517	(25,740)(a)	11,266
Power Generation	575	3,197	18,487 (b)	1,828
Coal Mining	2,256	1,092	2,575	3,217
Energy Marketing	(4,404)	6,902	(1,156)	7,565
Corporate	(9,110)(c)	(2,061)	13,205 (c)	(7,889)
Inter-segment eliminations	(74)	(36)	364	(76)
Total	$(3,853)	$19,522	$46,353	$44,542

(a) 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 in the first quarter of 2009. The lower prices at March 31, 2009 resulted in a $27.8 million after-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.

(b) Includes $16.9 million after-tax gain on sale to MEAN of 23.5% ownership interest in Wygen I power generation facility.

(c) Includes $8.7 million net mark-to-market loss for the three months ended September 30, 2009 and a $37.8 million net mark-to-market gain for the nine months ended September 30, 2009.

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Depreciation, depletion and amortization				
Utilities:				
Electric Utilities	$10,682	$10,630	$32,606	$26,269
Gas Utilities	7,366	6,567	23,045	6,567
Non-regulated Energy:				
Oil and Gas	7,142	9,401	22,281	25,761
Power Generation	961	1,111	2,812	3,504
Coal Mining	3,502	2,658	11,076	6,510
Energy Marketing	122	159	384	527
Corporate	49	299	331	1,861
Total	$29,824	$30,825	$92,535	$70,999

	September 30, 2009	December 31, 2008	September 30, 2008
Total assets			
Utilities:			
Electric Utilities	$1,592,852	$1,485,040	$1,284,150
Gas Utilities	619,855	733,377	753,649
Non-regulated Energy:			
Oil and Gas	340,046	403,583	465,118
Power Generation	120,426	155,819	145,784
Coal Mining	79,796	75,872	70,582
Energy Marketing	341,720	339,543	364,626
Corporate	73,640	186,409	142,468
Discontinued operations	—	246	322
Total	$3,168,335	$3,379,889	$3,226,699

(13) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sector expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

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

· Commodity price risk associated with our marketing businesses, our natural long position with crude oil and natural gas reserves and production, and fuel procurement for certain of our gas-fired generation assets;

· Interest rate risk associated with variable rate credit facilities;

· Interest rate risk associated with 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 2 of the Notes to our Consolidated Financial Statements in our 2008 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 and Note 15.

Trading Activities

Natural Gas and Crude Oil Marketing

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

Contracts and other activities at our natural gas and crude oil marketing operations are accounted for under the accounting standards for energy trading contracts. As such, all of the contracts and other activities at our natural gas and crude oil marketing operations that meet the definition of a derivative are accounted for at fair value. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Condensed Consolidated Statements of Income. ASC 940-325-S99 precludes mark-to-market accounting for energy trading contracts that are not defined as derivatives pursuant to accounting standards for derivatives. As part of our natural gas and crude oil marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, ASC 815 generally does not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas and crude oil marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions results from these accounting requirements.

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

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

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

The contract or notional amounts and terms of our natural gas and crude oil marketing activities and derivative commodity instruments are as follows:

	Outstanding at September 30, 2009		Outstanding at December 31, 2008		Outstanding at September 30, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	246,175	25	187,368	34	184,099	37
Natural gas basis swaps sold	242,246	25	186,710	34	180,322	37
Natural gas fixed-for-float swaps purchased	89,371	18	85,412	24	73,872	24
Natural gas fixed-for-float swaps sold	94,619	18	90,171	24	84,786	24
Natural gas physical purchases	150,698	18	131,937	16	146,273	18
Natural gas physical sales	179,134	18	145,706	21	182,512	24
Natural gas options purchased	1,227	6	1,440	3	3,958	6
Natural gas options sold	1,227	6	1,440	3	3,958	6

	Outstanding at September 30, 2009		Outstanding at December 31, 2008		Outstanding at September 30, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	3,263	4	7,446	12	5,994	15
Crude oil physical sales	3,126	4	6,251	12	4,690	15
Crude oil swaps/options purchased	—	—	435	24	465	24
Crude oil swaps/options sold	64	3	502	24	525	24

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on September 30, 2009, December 31, 2008 and September 30, 2008, 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):

	September 30, 2009	December 31, 2008	September 30, 2008
Current derivative assets	$38,650	$52,723	$66,807
Non-current derivative assets	$4,547	$(145)	$(1,140)
Current derivative liabilities	$14,668	$15,553	$22,292
Non-current derivative liabilities	$646	$(777)	$(227)
Cash collateral (receivable)/payable included in derivative assets/liabilities(a)	$(4,829)	$16,315	$1,789
Unrealized gain	$23,054	$54,117	$45,391

(a) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between us and a counterparty. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. At September 30, 2009, we had the right to reclaim cash collateral of $4.8 million. At December 31, 2008 and September 30, 2008, we had an obligation to return cash collateral of $16.3 million and $1.8 million, respectively.

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 September 30, 2009, December 31, 2008 and September 30, 2008, the market adjustments recorded in inventory were $(1.3) million, $(9.4) million and $(15.1) 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 September 30, 2009, December 31, 2008 and September 30, 2008, we had a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on those over-the-counter swaps and options. These transactions were designated at inception as cash flow hedges, properly documented and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

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

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

	September 30, 2009		December 31, 2008		September 30, 2008	
	Crude Oil Swaps/Options	Natural Gas Swaps	Crude Oil Swaps/Options	Natural Gas Swaps	Crude Oil Swaps/Options	Natural Gas Swaps
Notional*	450,000	9,448,050	435,000	8,523,500	465,000	9,231,000
Maximum terms in years**	0.25	0.75	0.25	1.00	0.25	1.08
Current derivative assets	$5,091	$8,607	$7,674	$11,828	$1,309	$7,391
Non-current derivative assets	$128	$241	$3,464	$3,749	$909	$1,632
Current derivative liabilities	$—	$1,079	$—	$—	$3,955	$236
Non-current derivative liabilities	$1,895	$1,934	$10	$297	$1,268	$165
Pre-tax accumulated other comprehensive income (loss) included in balance sheet	$2,840	$5,835	$9,642	$15,280	$(4,308)	$8,622
Earnings	$484	$—	$1,486	$—	$1,303	$—

* 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 September 30, 2009 market prices, a $9.7 million gain would be realized and reported in pre-tax earnings during the next twelve months related to hedges of production. Estimated and actual realized gains will likely change during the next twelve 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, 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 September 30, 2009		Outstanding at December 31, 2008		Outstanding at September 30, 2008	
	Notional Amounts*	Latest Expiration (months)	Notional Amounts*	Latest Expiration (months)	Notional Amounts*	Latest Expiration (months)
Natural gas futures purchased	9,790	18	1,290	3	2,730	6
Natural gas options purchased	3,870	6	3,990	3	8,760	6
Natural gas options sold	—	—	820	3	1,800	6
Natural gas basis swaps purchased	378	6	—	—	—	—

*gas in thousands of MMBtus

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

	September 30, 2009	December 31, 2008	September 30, 2008
Current derivative assets(a)	$4,603	$4,224	$9,424
Non-current derivative assets	$522	$—	$—
Current derivative liabilities	$—	$2,924	$5,241
Non-current derivative liabilities	$75	$—	$—
Net unrealized (gain) loss included in regulatory assets	$(1,105)	$11,668	$17,991
Cash collateral included in derivative assets/liabilities(b)	$(1,840)	$(8,744)	$(12,750)

(a) Includes option premium of $2.1 million, $4.2 million and $9.4 million at September 30, 2009, December 31, 2008 and September 30, 2008, respectively, which will be recorded as a regulatory asset upon settlement of the options.

(b) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between us and a counterparty. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. At September 30, 2009, December 31, 2008 and September 30, 2008, we had the right to reclaim cash collateral of $1.8 million, $8.7 million and $12.8 million, respectively.

Weather Derivatives

As approved in the State of Iowa, Iowa Gas uses a weather derivative to mitigate the effect of fluctuations from normal weather, but not for trading or speculative purposes. Accounting standards for derivatives require that weather derivatives are accounted for by recording an asset or liability for the difference between the actual and contracted threshold cooling or heating degree days in the period, multiplied by the contract price. Any gains and losses recorded on the contracts are recorded as regulatory assets or regulatory liabilities. Contracts totaling $0.5 million are included in Other current assets on the accompanying Condensed Consolidated Balance Sheet as of September 30, 2009.

Fuel in Storage

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

On September 30, 2009, we had the following swaps and related balances (dollars, in thousands):

Notional*	232,500
Maximum terms in months	12
Current derivative asset	$—
Non-current derivative asset	$—
Current derivative liability	$42
Non-current derivative liability	$—
Pre-tax accumulated other comprehensive income	$42
Unrealized gain	$—

* Gas in MMBtus

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Financing Activities

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

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

	September 30, 2009		December 31, 2008		September 30, 2008	
	Designated Interest Rate Swaps	Interest Rate Swaps*	Designated Interest Rate Swaps	Interest Rate Swaps*	Designated Interest Rate Swaps	Designated 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	7.25	1.25	$8.00	$ 1.00	$8.00	$ 0.25
Current derivative assets	$—	$ —	$—	$ —	$—	$ —
Non-current derivative assets	$—	$ —	$—	$ —	$—	$ —
Current derivative liabilities	$6,513	$ 46,332	$5,740	$ 94,440	$2,588	$ 28,097
Non-current derivative liabilities	$12,941	$ 10,333	$22,495	$ —	$5,586	$ —
Pre-tax accumulated other comprehensive loss included in balance sheet	$(19,454)	$ —	$(28,235)	$ —	$(8,174)	$ (28,097)
Pre-tax gain/(loss) included in Income Statement	$—	$ 37,775	$—	$ (94,440)	$—	$ —

*The $250 million notional amount interest rate swaps represent the interest rate swaps that we de-designated as hedges in the fourth quarter of 2008 as disclosed in Note 2 of the Notes to our Consolidated Financial Statements in our 2008 Annual Report on Form 10-K.

Based on September 30, 2009 market interest rates and balances related to our $150 million in designated interest rate swaps, a loss of approximately $6.5 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change. Note 14 provides further information related to the $250 million notional swaps that are not designated as hedges for accounting purposes.

Foreign Exchange Contracts

Our Energy Marketing Segment conducts its gas marketing in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange risk for us. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollar.

The outstanding forward exchange contracts, which had a fair value of $0.1 million, $(0.2) million and $0.4 million at September 30, 2009, December 31, 2008 and September 30, 2008, respectively, have been recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. For the three and nine months ended September 30, 2009, the unrealized foreign exchange gain was $0.3 million and $0.3 million, respectively, while for the three and nine months ended September 30, 2008, the amount of unrealized foreign exchange gain was $0.1 million and $0.9 million, respectively. For the three and nine months ended September 30, 2009, the realized foreign currency gain was $0.9 million and $1.7 million, respectively, while for the three and nine months ended September 30, 2008, the amount of foreign currency (loss) gain was $(0.3) million and $0.1 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.

All forward exchange contracts outstanding at September 30, 2009 will settle by December 24, 2009 and were as follows (dollars, in thousands):

	Outstanding at September 30, 2009		Outstanding at December 31, 2008		Outstanding at September 30, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Canadian dollars purchased	$2,500	1	$52,000	1	$25,000	1
Canadian dollars sold	$13,000	3	$—	—	$3,000	1

(14) QUANTITATIVE DISCLOSURES RELATED TO DERIVATIVES

Fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions. Further, the amounts do not include net cash collateral of $6.7 million on deposit in margin accounts at September 30, 2009 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 and Note 15. The following table presents the fair value and balance sheet classification of our derivative instruments as of September 30, 2009 (in thousands):

Fair Value as of September 30, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets – current	$6,914	$4,762
Commodity derivatives	Derivative assets – non-current	7	—
Commodity derivatives	Derivative liabilities – current	—	645
Commodity derivatives	Derivative liabilities – non-current	—	9
Interest rate swaps	Derivative liabilities – current	—	6,513
Interest rate swaps	Derivative liabilities – non-current	—	12,941
Total derivatives designated as hedges		$6,921	$24,870
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets – current	$201,011	$152,933
Commodity derivatives	Derivative assets – non-current	11,407	5,976
Commodity derivatives	Derivative liabilities – current	10,672	25,803
Commodity derivatives	Derivative liabilities – non-current	1,201	5,742
Interest rate swap	Derivative liabilities – current	—	46,332
Interest rate swap	Derivative liabilities – non-current	—	10,333
Foreign currency derivative	Derivative asset – current	52	—
Foreign currency derivatives	Derivative liabilities – current	58	71
Total derivatives not designated as hedges		$224,401	$247,190

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 nine months ended September 30, 2009.

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 nine months ended September 30, 2009 is presented as follows:

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

Fair Value Hedges
(in thousands)

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$3,868	$10,749
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue	(2,552)	(8,092)
		$1,316	$2,657

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Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2009 is presented as follows:

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

Cash Flow Hedges
(in thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/ (Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/ (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/ (Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(2,941)	Interest expense	$(582)		$—
Commodity derivatives	(7,781)	Operating revenue	5,976	Operating revenue	(147)
Total	$(10,722)		$5,394		$(147)

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

Cash Flow Hedges
(in thousands)

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	$8,780	Interest expense	$(2,540)		$—
Commodity derivatives	(16,289)	Operating revenue	19,157	Operating revenue	(1,241)
Total	$(7,509)		$16,617		$(1,241)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedges on our Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2009 is presented below.

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

Derivatives Not Designated as Hedging Instruments
(in thousands)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended September 30, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$(8,531)	$(25,895)
Interest rate swap	Interest rate swap – unrealized (loss) gain	(8,694)	37,775
Foreign currency contracts	Operating revenue	374	267
		$(16,851)	$12,147

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(15) DERIVATIVE FINANCIAL INSTRUMENTS AND 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 and 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.

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 September 30, 2009, December 31, 2008 and September 30, 2008. 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.

Recurring Fair Value Measures (in thousands)	At Fair Value as of September 30, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral(a)	Total
Assets:					
Commodity derivatives	$—	$213,296	$11,519	$(162,537)	$62,278
Money market funds	6,005	—	—	—	6,005
Foreign currency derivatives	—	111	—	—	111
	$6,005	$213,407	$11,519	$(162,537)	$68,394
Liabilities:					
Commodity derivatives	$—	$183,566	$5,908	$(169,206)	$20,268
Foreign currency derivatives	—	71	—	—	71
Interest rate swaps	—	76,119	—	—	76,119
Total	$—	$259,756	$5,908	$(169,206)	$96,458

Recurring Fair Value Measures (in thousands)	At Fair Value as of December 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral(a)	Total
Assets:					
Commodity derivatives	$—	$267,932	$28,407	$(208,952)	$87,387
Liabilities:					
Commodity derivatives	$—	$211,672	$12,009	$(201,381)	$22,300
Foreign currency derivatives	—	227	—	—	227
Interest rate swaps	—	122,675	—	—	122,675
Total	$—	$334,574	$12,009	$(201,381)	$145,202

Recurring Fair Value Measures (in thousands)	At Fair Value as of September 30, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral(a)	Total
Assets:					
Short-term investments	$—	$—	$6,310	$—	$6,310
Commodity derivatives	—	261,456	19,368	(194,989)	85,835
Foreign currency derivatives	—	423	—	—	423
Total	$—	$261,879	$25,678	$(194,989)	$92,568
Liabilities:					
Commodity derivatives	$—	$225,831	$13,048	$(205,950)	$32,929
Interest rate swaps	—	36,272	—	—	36,272
Total	$—	$262,103	$13,048	$(205,950)	$69,201

(a) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between us and a counterparty. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. Cash collateral on deposit in margin accounts at September 30, 2009, December 31, 2008 and September 30, 2008 totaled a net $6.7 million, $(7.6) million and $11.0 million, respectively.

The following tables present the changes in level 3 recurring fair value for the three and nine months ended September 30, 2009 and 2008, respectively (in thousands):

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
	Commodity Derivatives	Commodity Derivatives
Balance as of beginning of period	$5,153	$16,398
Realized and unrealized losses	(2,628)	(4,183)
Purchases, issuance and settlements	2,590	(3,464)
Transfers in and/or out of level 3(a)	496	(3,140)
Balances as of September 30, 2009	$5,611	$5,611
Changes in unrealized losses relating to instruments still held as of September 30, 2009	$3,556	$(6,899)

(a) Transfers into level 3 represent existing assets and liabilities that were previously categorized as a higher level for which the inputs became unobservable. Transfers out of level 3 represent existing assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

	Three Months Ended September 30, 2008		
	Commodity Derivatives	Short-term Investments	Total
Balance as of July 1, 2008	$11,332	$7,309	$18,641
Realized and unrealized losses	(3,142)	(49)	(3,191)
Purchases, issuance and settlements	(1,869)	(950)	(2,819)
Balances as of September 30, 2008	$6,321	$6,310	$12,631
Changes in unrealized gains relating to instruments still held as of September 30, 2008	$(4,579)	$(49)	$(4,628)

	Nine Months Ended September 30, 2008		
	Commodity Derivatives	Short-term Investments	Total
Balance as of January 1, 2008	$6,422	$—	$6,422
Realized and unrealized gains (losses)	3,688	(215)	3,473
Purchases, issuance and settlements	(3,789)	6,525	2,736
Balances as of September 30, 2008	$6,321	$6,310	$12,631
Changes in unrealized losses relating to instruments still held as of September 30, 2008	$(4,641)	$(215)	$(4,856)

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the accompanying Condensed Consolidated Statements of Income. We believe an analysis of commodity derivatives classified as level 3 needs to be undertaken with the understanding that these items may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter. Short-term investments included in level 3 represent auction rate securities held at September 30, 2008. The unrealized losses for these investments are recognized in Accumulated other comprehensive loss on the accompanying Condensed Consolidated Balance Sheets.

Fair Value of Financial Instruments

The estimated fair value of our financial instruments at September 30, 2009 is as follows (in thousands):

	Carrying Amount	Fair Value
Cash, cash equivalents and restricted cash	$137,687	$137,687
Derivative financial instruments – assets	$62,389	$62,389
Derivative financial instruments – liabilities	$96,458	$96,458
Notes payable	$350,500	$350,500
Long-term debt, including current maturities	$751,306	$848,900

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

Cash, Cash Equivalents and Restricted Cash

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

Derivative Financial Instruments

These instruments are carried at fair value. The Company's fair value measurements are developed using a variety of inputs by its 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 the Company's 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 15.

Notes Payable

The carrying amount approximates fair value due to their 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.

(16) COMMITMENTS AND CONTINGENCIES

Legal Proceedings

We are subject to various legal proceedings, claims and litigation as described in Note 18 of the Notes to our Consolidated Financial Statements in our 2008 Annual Report on Form 10-K. Except as described below, there have been no material developments in any previously reported proceedings or any new material proceedings that have developed or material proceedings that have terminated during the first nine months of 2009.

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of September 30, 2009, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

FERC Compliance Investigation

During 2007, following an internal review of natural gas marketing activities conducted within the Energy Marketing segment, we identified possible instances of noncompliance with regulatory requirements applicable to those activities. We notified the enforcement staff of FERC of our findings and shared information with the purpose of resolving any potential enforcement concerns. On August 24, 2009, FERC entered its Order approving a stipulation and consent agreement between the FERC Office of Enforcement and Enserco Energy Inc., which settled all matters presented to FERC in the 2007 self-report. Pursuant to the Agreement and Order, we agreed to pay a civil penalty of $1.4 million, and submit semi-annual monitoring reports to FERC's Office of Enforcement for one year. No further enforcement action was taken or is expected relative to the matters presented to the Office of Enforcement. The settlement of this matter, including the payment of a civil penalty by Enserco Energy Inc., did not have a material impact upon our overall consolidated results of operations.

Partial Sale of Wygen I to MEAN

During August 2008, we entered into a definitive agreement to sell a 23.5% ownership interest in the Wygen I plant to MEAN. The sale was completed in January 2009 for a price of $51.0 million, which was based on the then-current replacement cost for the coal-fired plant. We realized an after-tax gain of $16.9 million on the sale, and our property, plant and equipment was reduced by $26.2 million. We retain responsibility for operations of the plant, and at closing entered into a site lease, and operating agreements with MEAN for coal supply and operations. In addition, we terminated a 10-year power purchase contract requiring MEAN to purchase 20 MW of power annually from Wygen I.

Partial Sale of Wygen III to MDU

On April 9, 2009, Black Hills Power sold to MDU a 25% ownership interest in its Wygen III generation facility currently under construction. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received of which $30.2 million was used to pay down a portion of the Acquisition Facility. MDU will continue to reimburse Black Hills Power for its 25% of the total costs paid to complete the project. In conjunction with the sales transaction, we also modified the 2004 PPA between Black Hills Power and MDU under which Black Hills Power supplied MDU with 74 MW of capacity and energy through 2016. The power purchase agreement with MDU now provides that once online, the first 25 MW of MDU's required 74 MW will be supplied from its ownership interest in Wygen III. During periods of reduced production at Wygen III, or during periods when Wygen III is offline, we will provide MDU with its 25 MW from our other generation facilities or from system purchases.

Long-Term Power Sales Agreement

In March 2009, our 10-year power sales contract between MEAN and Black Hills Power that originally would have expired in 2013 was re-negotiated and extended until 2023. Under the new contract, MEAN will purchase 20 MW of unit-contingent capacity from the Neil Simpson II and Wygen III plants, with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II plants are as follows:

2009-2017	20 MW – 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW – 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW – 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW – 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

Power Purchase Agreement

In April 2009, Cheyenne Light entered into an agreement to purchase 30 MW of renewable energy from Duke Energy's Silver Sage wind site through a 20-year PPA. Commercial operations commenced on October 1, 2009. Under a separate inter-company agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

Extension of Long-Term Power Purchase Agreement

On September 29, 2009, FERC approved an extension of the PPA between Black Hills Wyoming and Cheyenne Light. The 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility, which was scheduled to expire in 2013, has been extended through December 31, 2022. In addition to establishing rates, terms and conditions for the sale of capacity and energy in this extension, the PPA grants Cheyenne Light an option to purchase Black Hills Wyoming's ownership in the Wygen I facility during years one to seven of the ten year term of the PPA. The purchase price related to the option is fixed at $2.55 million per MW which is the equivalent of the estimated price of new construction of the Wygen III plant. This price is reduced annually by an amount of annual depreciation.

(17) ACQUISITION

Aquila Transaction

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and four regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. See Note 21 of the Notes to our Consolidated Financial Statements in our 2008 Annual Report on Form 10-K for additional information.

This acquisition has been accounted for under the purchase method of accounting, and accordingly, the purchase price has been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. Adjustments to the purchase price allocation during the nine months ended September 30, 2009 included working capital and tax adjustments of $5.4 million. Allocation of the purchase price as of September 30, 2009 is as follows (in thousands):

Current assets	$113,486
Property, plant and equipment	542,094
Derivative assets	4,695
Goodwill	339,028
Intangible assets	4,884
Deferred assets	76,143
	$1,080,330
Current liabilities	$95,257
Deferred credits and other liabilities	54,550
	$149,807
Net assets	$930,523

After finalization of the working capital adjustment, the allocation of the purchase price resulted in $339.0 million of goodwill and $4.9 million of intangible assets. Goodwill of $245.0 million was allocated to the Electric Utility and $94.0 million was allocated to the Gas Utilities.

The results of operations of the acquired regulated utilities have been included in the accompanying Condensed Consolidated Financial Statements since the acquisition date.

The following pro-forma consolidated results of operations have been prepared as if the acquisition of the regulated utilities had occurred on January 1, 2008 (in thousands, except per share amounts):

	Three Month Period Ended September 30, 2008	Nine Month Period Ended September 30, 2008
Operating revenues	$314,090	$1,140,913
Income from continuing operations	19,890	68,809
Net income available for common stock	165,279	228,295
Earnings per share –		
Basic:		
Continuing operations	$0.52	$1.80
Total	$4.32	$5.99
Diluted:		
Continuing operations	$0.52	$1.79
Total	$4.30	$5.94

The above pro-forma information is presented for informational purposes only and is not necessarily indicative of the results of operations that would have been achieved had the acquisition been consummated at that time; nor is it intended to be a projection of future results.

(18) INCOME TAXES

Our effective tax rate for the nine months ended September 30, 2009 was lower than previous periods as a result of a positive adjustment in the first quarter of 2009 for a previously recorded tax position. We recorded a $3.8 million reduction in tax expense in our Oil and Gas segment due to a re-measurement of this position.

(19) DISCONTINUED OPERATIONS

Results of operations and the related charges for discontinued operations have been classified as "Income from discontinued operations, net of taxes" in the accompanying Condensed Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Condensed Consolidated Balance Sheets as "Assets of discontinued operations" and "Liabilities of discontinued operations." For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

Sale of IPP Assets

On April 29, 2008, we entered into a definitive agreement to sell seven of our IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, we received net pre-tax cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and the required payoff of approximately $67.5 million of associated project level debt. The after-tax gain recorded on the asset sale, after finalization of the working capital and tax adjustments, was $142.2 million, of which $2.4 million was recorded in 2009 and $139.7 million was recorded in 2008 in discontinued operations.

Revenues and net income from the discontinued operations associated with the divested IPP plants were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008*	2009	2008*
Operating revenues	$—	$5,507	$—	$59,572
Pre-tax income from discontinued operations	—	5,288	1,190	27,141
Gain on sale	—	235,671	—	235,671
Income tax (expense) benefit	1,673	(95,849)	1,249	(103,803)
Net income from discontinued operations	$1,673	$145,110	$2,439	$159,009

* In accordance with GAAP, during the second quarter of 2008, the Company ceased recording depreciation and amortization expense on the IPP facilities.

The indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations were $0 million and $7.7 million after-tax for the three and nine months ended September 30, 2008, respectively. These allocated costs remain in the Power Generation segment.

Interest expenses included within the operations of the discontinued entities were recorded pursuant to accounting standards for discontinued operations and include interest expense on debt which was required to be repaid as a result of the sale transaction. Interest expense was allocated to discontinued operations based on the ratio of the assets sold to total Company net assets, excluding the known debt repayment. For the three and nine months ended September 30, 2008, respectively, interest expense allocated to discontinued operations was $0 million and $4.7 million.

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(20) 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.

(21) SUBSEQUENT EVENTS

Black Hills Power Bond Issuance

On October 27, 2009, our regulated utility, Black Hills Power, completed a $180 million first mortgage bond issuance. The bonds were priced at 99.931% of par and a reoffer yield of 6.13%. The bonds mature November 1, 2039 and carry an annual interest rate of 6.125%, which will be paid semi-annually. We received proceeds of $178.3 million net of underwriting fees which were used to repay borrowings under the Corporate Credit Facility. Estimated deferred finance costs of $1.9 million were capitalized and will be amortized over the life of the bonds.

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 202,100 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 33,300 customers in Wyoming. Our Gas Utilities segment serves approximately 524,000 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil and related services.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 90.

Significant Events

Wygen III Power Plant Project and Partial Sale of Wygen III to MDU

We are currently constructing Wygen III, a 110 MW coal-fired base load electric generating facility located near Gillette, Wyoming. Construction is currently expected to be completed by April 1, 2010. The expected cost of construction is approximately $247 million, which includes estimates for AFUDC.

A 2004 Power Purchase Agreement between Black Hills Power and MDU included an option for MDU to purchase an ownership interest in Wygen III. MDU exercised this option, and under an agreement entered into in April 2009, we will retain an undivided ownership of 75% of the facility with MDU owning the remaining 25%. At closing we received proceeds of $32.8 million as MDU reimbursed us for its 25% of the total costs incurred to date on the ongoing construction of the facility. We will retain responsibility for operations of the facility with a life-of-plant site lease and agreements with MDU for operations and coal supply. In conjunction with the sales transaction, we also modified the 2004 PPA under which Black Hills Power supplied MDU with 74 MW of capacity and energy through 2016. The PPA with MDU now provides that once online, the first 25 MW of MDU's required 74 MW will be supplied from its ownership interest in Wygen III. During periods of reduced production at Wygen III, or during periods when Wygen III is offline, we will provide MDU with its first 25 MW from our other generation facilities or from system purchases.

Partial Sale of Wygen I to MEAN

In August 2008, we entered into a definitive agreement to sell a 23.5% ownership interest in the Wygen I plant to MEAN. The sale was completed in January 2009 for a price of $51.0 million, which was based on the then current replacement cost for the coal-fired plant. We realized an after-tax gain of $16.9 million on the sale, and our property, plant and equipment was reduced by $26.2 million. We retain responsibility for operations of the plant, and at closing entered into a site lease and operating agreements with MEAN for coal supply and operations. In addition, we terminated a 10-year power purchase contract requiring MEAN to purchase 20 MW of power annually from Wygen I.

Extension of Long-Term Power Sales Agreement with MEAN

In March 2009, our 10-year power sales contract between MEAN and Black Hills Power that originally expired in 2013 was re-negotiated and extended until 2023. Under the new contract, MEAN will purchase 20 MW of unit-contingent capacity from the Neil Simpson II and the Wygen III plants with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II plants are as follows:

2009-2017	20 MW – 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW – 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW – 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW – 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

Colorado Electric Resource Plan

In August 2008, Black Hills Energy filed a long-term Electric Resource Plan with the CPUC proposing to build five natural gas-fired power generation facilities totaling 350 MW to support the customers of Colorado Electric. In the first quarter of 2009, Colorado Electric received approval from the CPUC to build two power generation facilities representing approximately 90 MW each. The power generation facilities are part of a plan to replace the capacity and energy supplied under Colorado Electric's current PPA with PSCo, which expires on December 31, 2011. The initial decision of the CPUC waived the competitive bidding process for the two turbines; the remaining capacity and energy needs of the utility were to be acquired from other power producers through a competitive bid process. Our Power Generation segment was allowed to participate in the competitive bidding process. On September 29, 2009, our Power Generation segment was awarded the bid to provide 200 MW of power to Black Hills Energy through a 20-year PPA. The PPA is subject to approval by FERC. The 200 MW natural gas-fired electric generation facilities will be built in Colorado and are expected to be completed by December 31, 2011.

Silver Sage Wind Site

In April 2009, Cheyenne Light entered into an agreement to purchase 30 MW of renewable energy from Duke Energy's Silver Sage wind site through a 20-year PPA. Commercial operations commenced October 1, 2009. Under a separate inter-company agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

Power Purchase Agreement with MEAN

In July 2009, Black Hills Power entered into a five-year PPA with MEAN. The contract commences the month following the onset of commercial operations at Wygen III. Under this contract, MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

Extension of Long-Term Power Purchase Agreement

On September 29, 2009, FERC approved an extension of the PPA between Black Hills Wyoming and Cheyenne Light. The 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility, which was scheduled to expire in 2013, has been extended through December 31, 2022. In addition to establishing rates, terms and conditions for the sale of capacity and energy in this extension, the PPA grants Cheyenne Light an option to purchase Black Hills Wyoming's ownership in the Wygen I facility during years one to seven of the ten year term of the PPA. The purchase price related to the option is fixed at $2.55 million per MW which is the equivalent of the estimated price of new construction of the Wygen III plant. This price is reduced annually by an amount of annual depreciation.

Results of Operations

Executive Summary

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008.
Loss from continuing operations for the three month period ended September 30, 2009 was $3.9 million, or $0.10 per share, compared to income from continuing operations of $19.5 million, or $0.51 per share, reported for the same period in 2008. For the three month period ended September 30, 2009, net loss available for common stock was $2.2 million or $0.06 per share, compared to net income available for common stock of $164.9 million, or $4.29 per share, for the same period in 2008.

Included in 2009 are a full quarter of results from the utilities acquired from Aquila on July 14, 2008 and the impact of a $5.7 million after-tax non-cash loss, resulting from an unrealized net mark-to-market loss for certain interest rate swaps entered into in 2007.

The Utilities Group includes a full quarter of results of the electric and gas utilities acquired from Aquila on July 14, 2008. Earnings at our Electric Utilities reflect the impact of lower margins from off-system sales due to lower energy prices, lower retail sales due to milder summer weather, and higher interest expense, partially offset by the impact of AFUDC related to the Wygen III construction and increased retail margins from an approved rate case for transmission rates. Increased losses at our Gas Utilities reflect a full quarter of seasonal operations compared to the same period in 2008 and increased depreciation and property tax expense.

Earnings from the Oil and Gas segment decreased for the quarter due to a decrease in operating revenues resulting from lower oil and gas prices and lower production, partially offset by lower production taxes reflecting lower oil and gas prices. Average oil prices received, net of hedges, decreased 28% and average gas prices received, net of hedges, decreased 14%.

Increased earnings from the Coal Mining segment resulted from site lease income, higher volumes sold and lower diesel fuel costs, partially offset by lower average sales prices and increased depreciation.

Decreased earnings from the Energy Marketing segment reflect decreased unrealized mark-to-market margins, partially offset by increased realized natural gas and crude oil margins that were primarily impacted by differing market conditions between years.

Earnings from the Power Generation segment were impacted by lower margins due to the net earnings impact of replacing MEAN's 20 MW PPA with operating and site lease agreements related to their purchase of a 23.5% ownership interest in Wygen I, partially offset by operating fees charged to MEAN. For the three months ended September 30, 2008, results included the sale of nitrogen oxide Reclaim Trading Credits allocated to our Ontario facility which has been decommissioned.

Income from discontinued operations was $1.7 million, or $0.04 per share, for the three month period ended September 30, 2009, compared to $145.4 million, or $3.78 per share, for the same period in 2008. The Income from discontinued operations in 2009 relates to tax adjustments related to the sale in the IPP Transaction. The income from discontinued operations in 2008 relates primarily to the IPP Transaction in which we sold seven of our IPP plants.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008.
Income from continuing operations for the nine month period ended September 30, 2009 was $46.4 million, or $1.20 per share, compared to $44.5 million, or $1.16 per share, reported for the same period in 2008. For the nine month period ended September 30, 2009, net income available for common stock was $48.8 million or $1.26 per share, compared to $203.9 million, or $5.31 per share, for the same period in 2008.

Included in the 2009 results are the earnings from the utilities acquired from Aquila on July 14, 2008 and impacts from the following notable items:

· $16.9 million after-tax gain from the sale of a 23.5% interest in the Wygen I generation facility on January 22, 2009;

· $24.6 million after-tax non-cash gain, resulting from an unrealized net mark-to-market gain for certain interest rate swaps entered into in 2007; and

· Non-cash impairment charge of oil and gas assets totaling $27.8 million after-tax, driven by lower natural gas and crude oil prices at the end of the first quarter of 2009.

The Utilities Group's 2009 results include a full nine months of earnings from the electric and gas utilities acquired from Aquila on July 14, 2008. Earnings at our Electric Utilities reflect the impact of increased margins from an approved rate case for transmission rates and the impact of AFUDC related to the Wygen III construction partially offset by lower margins from off-system sales due to lower energy prices, and higher interest expense.

Earnings from the Oil and Gas segment decreased from 2008 due to a decrease in operating revenues reflecting lower oil and gas prices and lower production and a first quarter of 2009 impairment charge, partially offset by lower production taxes and LOE costs compared to 2008. Average oil prices received, net of hedges, decreased 36% and average gas prices received, net of hedges, decreased 33%.

Lower earnings from the Coal Mining segment in 2009 resulted from lower volumes on coal sales, increased depreciation and coal taxes, partially offset by revenue increases from higher average sale prices, site lease income and lower diesel fuel costs.

Lower earnings from the Energy Marketing segment in 2009 reflect unrealized mark-to-market losses, partially offset by higher realized natural gas and crude oil margins received. Realized natural gas margins and crude oil margins were primarily impacted by differing market conditions between years.

Increased earnings from the Power Generation segment in 2009 were impacted by a $16.9 million after-tax gain on the sale of a 23.5% ownership interest in the Wygen I power generation facility to MEAN and partially offset by increased interest expense and lower margins due to the net earnings impact of replacing the 20 MW PPA with operating and site lease agreements related to MEAN's purchase of the 23.5% ownership interest in Wygen I. In addition, for the nine months ended September 30, 2008, results included $11.8 million of pre-tax allocated indirect corporate costs and inter-segment net interest expense not classified to discontinued operations for the IPP Transaction, as well as the sale of nitrogen oxide Reclaim Trading Credits allocated to our Ontario facility which has been decommissioned.

Income from discontinued operations was $2.4 million, or $0.06 per share, for the nine month period ended September 30, 2009, compared to $159.5 million, or $4.15 per share, for the same period in 2008. The Income from discontinued operations in 2009 relates to working capital and tax adjustments and the related impact of the gain on sale from the IPP Transaction.

Consolidated Results

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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues				
Utilities	$191,634	$220,581	$796,973	$413,449
Non-regulated Energy	34,165	71,311	124,117	184,566
	$225,799	$291,892	$921,090	$598,015
Income (loss) from continuing operations				
Utilities	$7,053	$8,911	$38,618	$28,631
Non-regulated Energy	(1,796)	12,672	(5,470)	23,800
Corporate	(9,110)	(2,061)	13,205	(7,889)
	$(3,853)	$19,522	$46,353	$44,542

Income from continuing operations decreased $23.4 million for the three months ended September 30, 2009 reflecting the following:

Utilities

- A $0.2 million decrease in Electric Utilities earnings
- A $1.6 million decrease in the Gas Utilities segment

Non-regulated Energy

- A $1.7 million decrease in Oil and Gas earnings
- A $1.2 million increase in Coal Mining earnings
- An $11.3 million decrease in Energy Marketing earnings
- A $2.6 million decrease in Power Generation earnings

Corporate

- A $7.0 million decrease in corporate earnings

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Income from continuing operations increased $1.8 million for the nine months ended September 30, 2009 reflecting the following:

Utilities

- A $6.1 million decrease in Electric Utilities earnings
- A $16.1 million increase in the Gas Utilities segment

Non-regulated Energy

- A $37.0 million decrease in Oil and Gas earnings
- A $0.6 million decrease in Coal Mining earnings
- An $8.7 million decrease in Energy Marketing earnings
- A $16.7 million increase in Power Generation earnings

Corporate

- A $21.1 million increase in corporate earnings

See the following discussion under the captions “Utilities Group” and “Non-regulated Energy Group” for more detail on our results of operations by business segment.

Utilities Group

We acquired from Aquila a regulated electric utility in Colorado and four regulated gas utilities operating in Colorado, Nebraska, Iowa and Kansas. Operations from the acquired utilities have been included in the Utilities Group results from the July 14, 2008 acquisition date.

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

Electric Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue – electric	$126,025	$131,193	$361,198	$295,946
Revenue – gas	3,141	5,785	24,062	34,570
Total revenue	129,166	136,978	385,260	330,516
Fuel and purchased power – electric	66,994	74,162	190,831	152,364
Purchased gas	912	3,596	13,873	24,051
Total fuel and purchased power	67,906	77,758	204,704	176,415
Gross margin – electric	59,031	57,031	170,367	143,582
Gross margin – gas	2,229	2,189	10,189	10,519
Total gross margin	61,260	59,220	180,556	154,101
Operating expenses	42,493	38,561	128,703	95,654
Operating income	$18,767	$20,659	$51,853	$58,447
Income from continuing operations and net income available for common stock	$10,537	$10,765	$24,395	$30,485

The following tables summarize regulated sales revenues, quantities generated and purchased, sales quantities and degree days for our Electric Utilities segment. Included in 2009 reported amounts for the periods are the operations of Colorado Electric, acquired July 14, 2008 as part of the Aquila Transaction:

Sales Revenues	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Residential:				
Black Hills Power	$11,132	$13,189	$35,804	$35,784
Cheyenne Light	6,512	6,967	21,093	23,800
Colorado Electric	18,586	17,182	50,274	17,182
Total Residential	36,230	37,338	107,171	76,766
Commercial:				
Black Hills Power	15,694	16,581	44,888	43,804
Cheyenne Light	13,424	13,669	38,050	38,018
Colorado Electric	15,088	15,322	42,259	15,322
Total Commercial	44,206	45,572	125,197	97,144
Industrial:				
Black Hills Power	4,714	5,500	14,494	16,338
Cheyenne Light	2,888	2,620	8,179	7,038
Colorado Electric	8,021	8,153	23,074	8,153
Total Industrial	15,623	16,273	45,747	31,529
Municipal:				
Black Hills Power	778	802	2,074	2,069
Cheyenne Light	230	240	701	711
Colorado Electric	1,179	1,197	3,351	1,197
Total Municipal	2,187	2,239	6,126	3,977
Contract Wholesale:				
Black Hills Power	6,488	6,862	18,672	20,063
Off-system Wholesale:				
Black Hills Power	9,625	13,213	24,610	47,548
Cheyenne Light	1,863	1,497	5,795	4,368
Colorado Electric	2,697	4,352	9,724	4,352
Total Off-system Wholesale	14,185	19,062	40,129	56,268
Other:				
Black Hills Power	4,655	3,211	13,838	9,362
Cheyenne Light	253	98	466	299
Colorado Electric	2,198	538	3,852	538
Total Other	7,106	3,847	18,156	10,199
Total Sales Revenues	$126,025	$131,193	$361,198	$295,946

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Quantities Generated and Purchased	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in MWh)			
Generated –				
Coal-fired:				
Black Hills Power	465,068	450,884	1,251,276	1,268,514
Cheyenne Light	200,489	196,937	577,217	586,635
Colorado Electric	63,760	79,793	187,091	79,793
Total Coal	729,317	727,614	2,015,584	1,934,942
Gas and Oil-fired:				
Black Hills Power	28,251	11,856	35,076	53,687
Cheyenne Light	—	—	—	—
Colorado Electric	2,297	525	2,496	525
Total Gas and Oil	30,548	12,381	37,572	54,212
Total Generated:				
Black Hills Power	493,319	462,740	1,286,352	1,322,201
Cheyenne Light	200,489	196,937	577,217	586,635
Colorado Electric	66,057	80,318	189,587	80,318
Total Generated	759,865	739,995	2,053,156	1,989,154
Purchased:				
Black Hills Power	420,332	404,148	1,304,362	1,256,835
Cheyenne Light	151,992	140,843	464,265	404,390
Colorado Electric	514,980	473,019	1,495,825	473,019
Total Purchased	1,087,304	1,018,010	3,264,452	2,134,244
Total Generated and Purchased:				
Black Hills Power	913,651	866,888	2,590,714	2,579,036
Cheyenne Light	352,481	337,780	1,041,482	991,025
Colorado Electric	581,037	553,337	1,685,412	553,337
Total Generated and Purchased	1,847,169	1,758,005	5,317,608	4,123,398

Quantity Sold	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in MWh)			
Residential:				
Black Hills Power	113,266	120,888	395,865	398,028
Cheyenne Light	59,384	60,986	189,610	193,653
Colorado Electric	166,993	140,945	444,223	140,945
Total Residential	339,643	322,819	1,029,698	732,626
Commercial:				
Black Hills Power	207,939	195,661	553,150	531,433
Cheyenne Light	152,376	153,615	439,476	440,382
Colorado Electric	187,959	168,422	507,123	168,422
Total Commercial	548,274	517,698	1,499,749	1,140,237
Industrial:				
Black Hills Power	80,222	107,380	260,190	319,077
Cheyenne Light	45,447	38,798	131,694	108,569
Colorado Electric	121,789	110,492	342,206	110,492
Total Industrial	247,458	256,670	734,090	538,138
Municipal:				
Black Hills Power	9,894	10,228	25,556	26,073
Cheyenne Light	742	809	2,449	2,571
Colorado Electric	11,705	10,713	29,696	10,713
Total Municipal	22,341	21,750	57,701	39,357
Contract Wholesale:				
Black Hills Power	161,796	165,872	473,723	494,457
Off-system Wholesale:				
Black Hills Power	309,770	241,546	784,173	753,057
Cheyenne Light	72,771	63,202	216,822	184,151
Colorado Electric	71,886	79,685	272,694	79,685
Total Off-system Wholesale	454,427	384,433	1,273,689	1,016,893
Total Quantity Sold:				
Black Hills Power	882,887	841,575	2,492,657	2,522,125
Cheyenne Light	330,720	317,410	980,051	929,326
Colorado Electric	560,332	510,257	1,595,942	510,257
Total Quantity Sold	1,773,939	1,669,242	5,068,650	3,961,708
Losses and Company Use:				
Black Hills Power	30,764	25,313	98,057	56,911
Cheyenne Light	21,761	20,370	61,431	61,699
Colorado Electric	20,705	43,080	89,470	43,080
Total Losses and Company Use	73,230	88,763	248,958	161,690

Total Energy	1,847,169	1,758,005	5,317,608	4,123,398

Degree Days	Three Months Ended September 30, 2009		2008	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual –				
Black Hills Power	178	(22)%	223	(2)%
Cheyenne Light	298	(9)%	317	(3)%
Colorado Electric	104	13%	75	(18)%
Cooling Degree Days:				
Actual –				
Black Hills Power	303	(39)%	453	(8)%
Cheyenne Light	179	(23)%	345	49%
Colorado Electric	620	(12)%	560	(2)%

Degree Days	Nine Months Ended September 30, 2009		2008	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Actual –				
Black Hills Power	4,705	4%	4,814	6%
Cheyenne Light	4,383	(7)%	4,859	3%
Colorado Electric	3,053	(10)%	75	(18)%
Cooling Degree Days:				
Actual –				
Black Hills Power	354	(41)%	482	(19)%
Cheyenne Light	203	(26)%	372	36%
Colorado Electric	804	(13)%	560	(2)%

Electric Utilities Power Plant Availability

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009		2008		2009		2008	
Coal-fired plants	94.5	%	96.4	%	92.0	%**	93.2	%*
Other plants	77.9	%***	98.7	%	90.6	%***	92.6	%
Total availability	88.3	%	97.3	%	91.4	%	93.0	%

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* Reflects major maintenance outages at our Ben French, Neil Simpson I and Osage coal-fired plants. The Ben French outage was scheduled for 25 days and was subsequently extended to accelerate major maintenance originally scheduled for 2009. The actual outage was 88 days and resulted in the plant's output being restored to its full rated capacity. The Osage outage was originally scheduled for approximately 10 days and lasted 52 days as a result of additional unplanned required maintenance. All the plants were online by the end of the second quarter of 2008.

** Reflects major maintenance outages at Neil Simpson I and Neil Simpson II coal-fired plants. 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. The outages were extended on both units for major rotor damage discovered during the overhauls.

*** Reflects unplanned outage at Pueblo Unit 5 gas-fired plant.

Cheyenne Light Natural Gas Distribution

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Sales Revenues (in thousands):				
Residential	$2,053	$3,419	$14,699	$20,262
Commercial	657	1,526	6,716	9,919
Industrial	266	656	2,073	3,799
Other	165	184	574	590
Total Sales Revenues	$3,141	$5,785	$24,062	$34,570
Sales Margins (in thousands):				
Residential	$1,624	$1,588	$6,990	$7,244
Commercial	379	368	2,296	2,357
Industrial	61	49	329	328
Other	165	184	574	590
Total Sales Margins	$2,229	$2,189	$10,189	$10,519
Volumes Sold (Dth):				
Residential	176,996	183,594	1,745,760	1,944,705
Commercial	120,348	116,840	1,037,984	1,112,664

Industrial	79,161	61,050	462,276	461,792
Total Volumes Sold	376,505	361,484	3,246,020	3,519,161

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008. Income from continuing operations for the Electric Utilities decreased $0.2 million from the prior period primarily due to the following:

· A $2.2 million decrease in margins from off-system sales reflecting the lower margins available in the current low energy price environment; and

· A $1.5 million increase in net interest expense due to additional debt associated with the acquisition of Colorado Electric.

Partially offsetting these were the following:

· A $1.5 million increase in other margins primarily related to an increase in transmission rates effective January 1, 2009 at Black Hills Power;

· Higher retail margins resulting from a full quarter of operations at Colorado Electric, which was purchased on July 14, 2008, which were partially offset by milder summer weather. Cooling degree days were below normal for the quarter; and

· Increased AFUDC of $1.8 million primarily due to construction of Wygen III and construction at Colorado Electric in 2009.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008. Income from continuing operations for the Electric Utilities decreased $6.1 million from the prior period primarily due to the following:

· A $6.1 million decrease in margins from off-system sales reflecting the lower margins available in the current low energy price environment;

· A $10.6 million increase in net interest expense due to additional debt associated with the acquisition of Colorado Electric; and

· A $2.5 million increase in employee benefit costs primarily associated with pension costs.

Partially offsetting these were the following:

· A $4.5 million increase in other margins primarily due to an increase in transmission rate effective January 1, 2009 at Black Hills Power; and

· Increased AFUDC of $4.7 million primarily due to construction of Wygen III and construction at Colorado Electric in 2009.

Gas Utilities

Operating results for the Gas Utilities are as follows:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008 *	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008 *
	(in thousands)			
Revenue:				
Natural gas – regulated	$56,854	$75,465	$392,595	$75,465
Other – non-regulated services	5,837	8,472	19,771	8,472
Total sales	62,691	83,937	412,366	83,937
Cost of sales:				
Natural gas – regulated	23,376	47,364	251,252	47,364
Other – non-regulated services	2,894	5,823	11,295	5,823
Total cost of sales	26,270	53,187	262,547	53,187
Gross margin	36,421	30,750	149,819	30,750
Operating expenses	37,656	29,777	116,568	29,777
Operating (loss) income	$(1,235)	$973	$33,251	$973
(Loss) income from continuing operations and net income (loss) available for common stock	$(3,484)	$(1,854)	$14,223	$(1,854)

* Gas utilities were purchased on July 14, 2008.

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The following table summarizes regulated Gas Utilities' sales revenues:

Sales Revenues	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008 *	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008 *
	(in thousands)			
Residential:				
Colorado	$5,127	$5,503	$43,277	$5,503
Nebraska	12,552	13,518	90,698	13,518
Iowa	9,773	11,423	81,184	11,423
Kansas	7,703	8,367	49,591	8,367
Total Residential	35,155	38,811	264,750	38,811
Commercial:				
Colorado	1,131	1,408	9,444	1,408
Nebraska	2,896	5,425	31,219	5,425
Iowa	3,950	6,436	36,325	6,436
Kansas	1,976	2,413	15,542	2,413
Total Commercial	9,953	15,682	92,530	15,682
Industrial:				
Colorado	450	1,341	1,159	1,341
Nebraska	345	686	2,435	686
Iowa	307	487	958	487
Kansas	5,764	13,926	10,349	13,926
Total Industrial	6,866	16,440	14,901	16,440
Transportation:				
Colorado	115	107	477	107
Nebraska	1,519	1,488	7,441	1,488
Iowa	793	533	2,837	533
Kansas	1,251	1,160	4,047	1,160
Total Transportation	3,678	3,288	14,802	3,288
Other:				
Colorado	24	17	82	17
Nebraska	406	371	1,592	371
Iowa	109	132	802	132
Kansas	663	724	3,136	724
Total Other	1,202	1,244	5,612	1,244
Total Regulated	56,854	75,465	392,595	75,465
Non-regulated Services	5,837	8,472	19,771	8,472
Total	$62,691	$83,937	$412,366	$83,937

* Gas utilities were purchased on July 14, 2008.

The following table summarizes regulated Gas Utilities' sales margins:

Sales Margins	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008*	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008*
	(in thousands)			
Residential:				
Colorado	$ 2,895	$ 1,670	$ 11,577	$ 1,670
Nebraska	7,637	5,847	31,767	5,847
Iowa	7,075	4,512	31,237	4,512
Kansas	5,433	6,442	20,781	6,442
Total Residential	23,040	18,471	95,362	18,471
Commercial:				
Colorado	515	297	2,130	297
Nebraska	1,357	1,544	8,298	1,544
Iowa	1,706	833	9,022	833
Kansas	1,021	1,339	4,516	1,339
Total Commercial	4,599	4,013	23,966	4,013
Industrial:				
Colorado	141	195	325	195
Nebraska	64	27	276	27
Iowa	26	863	116	863
Kansas	834	66	1,584	66
Total Industrial	1,065	1,151	2,301	1,151
Transportation:				
Colorado	114	107	476	107
Nebraska	1,520	533	7,441	533
Iowa	793	1,160	2,838	1,160
Kansas	1,251	1,488	4,048	1,488
Total Transportation	3,678	3,288	14,803	3,288
Other:				
Colorado	25	17	82	17
Nebraska	404	132	1,591	132
Iowa	110	662	803	662
Kansas	559	371	2,496	371
Total Other	1,098	1,182	4,972	1,182

Total Regulated	33,480	28,105	141,404	28,105
Non-regulated Services	2,941	2,645	8,415	2,645
Total	$ 36,421	$ 30,750	$ 149,819	$ 30,750

* Gas utilities were purchased on July 14, 2008.

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The following table summarizes regulated Gas Utilities' volumes sold:

Volumes Sold	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008 *	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008 *
	(in Dth)			
Residential:				
Colorado	505,857	448,358	3,998,997	448,358
Nebraska	909,794	735,153	8,349,868	735,153
Iowa	605,788	582,043	7,558,458	582,043
Kansas	542,182	414,348	4,551,485	414,348
Total Residential	2,563,621	2,179,902	24,458,808	2,179,902
Commercial:				
Colorado	142,070	131,333	945,349	131,333
Nebraska	366,579	433,634	3,567,604	433,634
Iowa	499,487	495,976	4,233,967	495,976
Kansas	230,693	174,908	1,759,774	174,908
Total Commercial	1,238,829	1,235,851	10,506,694	1,235,851
Industrial:				
Colorado	110,474	151,168	241,267	151,168
Nebraska	79,710	93,031	394,475	93,031
Iowa	63,646	45,728	154,329	45,728
Kansas	1,401,415	1,465,835	2,402,633	1,465,835
Total Industrial	1,655,245	1,755,762	3,192,704	1,755,762
Transportation:				
Colorado	110,158	123,564	541,958	123,564
Nebraska	5,222,591	5,776,382	18,637,020	5,776,382
Iowa	3,069,669	2,171,780	10,375,438	2,171,780
Kansas	3,756,752	4,083,444	10,774,330	4,083,444
Total Transportation	12,159,170	12,155,170	40,328,746	12,155,170
Other:				
Colorado	—	—	—	—
Nebraska	5	4	1,140	4
Iowa	3,833	2,898	52,341	2,898
Kansas	21,360	7,245	98,878	7,245
Total Other	25,198	10,147	152,359	10,147
Total Regulated	17,642,063	17,336,832	78,639,311	17,336,832

* Gas utilities were purchased on July 14, 2008.

Degree Days	Three Months Ended September 30, 2009		Nine Months Ended September 30, 2009	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	224	20 %	3,735	(1)%
Nebraska	100	10 %	3,645	3 %
Iowa	142	(8)%	4,353	3 %
Kansas*	67	68 %	2,765	(10)%
Combined Gas Utilities Heating Degree Days	141	5 %	3,831	(5)%

Degree Days	Three Months Ended September 30, 2008**		Nine Months Ended September 30, 2008**	
Heating Degree Days:	Actual	Variance From Normal	Actual	Variance From Normal
Colorado	183	(2)%	183	(2)%
Nebraska	65	(29)%	65	(29)%
Iowa	102	(34)%	102	(34)%
Kansas*	47	18 %	47	18 %
Combined Gas Utilities Heating Degree Days	116	(13)%	116	(13)%

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

** Results from the Gas Utilities for the three and nine month periods ended September 30, 2009 reflect operations from the gas utilities acquired from Aquila on July 14, 2008.

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

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008. Income from continuing operations for the Gas Utilities decreased $1.6 million from the prior period primarily due to the following:

- 2009 reflects a full quarter of summer season operations for the Gas Utilities purchased on July 14, 2008;
  - A $1.3 million increase in depreciation and property tax expense due to increased asset base; and
- A $0.2 million increase in net interest expense due to additional debt associated with the acquisition of the Gas Utilities.

Nine months ended September 30, 2009 reflects a full three quarters of operations for our Gas Utilities compared with 2008 when operations commenced on July 14, 2008.

Regulatory Matters – Utilities Group

The following summarizes our recent rate case activity:

In millions	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved
Nebraska Gas (1)	Gas	11/2006	9/2007	$16.3	$9.2
Iowa Gas (2)	Gas	6/2008	7/27/09	$13.6	$10.8
Colorado Gas (3)	Gas	6/2008	4/2009	$2.7	$1.4
Kansas Gas (4)	Gas	5/2009	10/02/09	$0.5	$0.5
Black Hills Power (5)	Electric	9/2008	1/2009	$4.5	$3.8
Black Hills Power (6)	Electric	9/2009	Pending	$32.0	Pending
Black Hills Power (7)	Electric	10/2009	Pending	$3.8	Pending

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

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

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

(4) Kansas Gas has requested a GSRS in the amount of $0.5 million annually. The KCC staff recommended approval of all projects submitted, the filed GSRS revenue requirement of $0.5 million, and that Kansas Gas be allowed to continue collecting its current GSRS amount of $0.3 million. The KCC issued an order on September 14, 2009 approving the request for $0.5 million and allowing Kansas Gas to continue collecting the $0.3 million previously authorized. The new rates had an effective date of October 1, 2009.

(5) 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.

(6) On September 29, 2009, Black Hills Power filed a rate case with the SDPUC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred during the past four years. Black Hills Power is seeking a 26.6% increase in annual utility revenues and anticipates that the new rates will be effective for our South Dakota customers on or around April 1, 2010. The proposed rate increase is subject to approval by the SDPUC.

(7) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred since 1995. Black Hills Power is seeking a 38.95% increase in annual utility revenues and anticipates that the new rates will be effective for our Wyoming customers on or around April 1, 2010, although recovery could be delayed until August 2010 as part of the regulatory process. The proposed rate increase is subject to approval by the WPSC.

Non-regulated Energy Group

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

Oil and Gas

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue	$17,887	$25,438	$52,227	$85,770
Operating expenses*	17,057	21,285	95,564	63,692
Operating income (loss)	$830	$4,153	$(43,337)	$22,078
(Loss) income from continuing operations and net income (loss) available for common stock	$(149)	$1,517	$(25,740)	$11,266

* Nine months ended September 30, 2009 operating expenses include a $43.3 million pre-tax ceiling test impairment charge.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Fuel production:				
Bbls of oil sold	91,091	95,248	286,405	298,035
Mcf of natural gas sold	2,574,036	2,873,353	7,916,515	8,293,364
Mcf equivalent sales	3,120,582	3,444,841	9,634,945	10,081,574

	Three Months Ended September 30,		Nine Months Ended September 30,			
	2009	2008	2009		2008	
Average price received: (a)						
Gas/Mcf (b)	$4.50	$5.26	$4.44	(c)	$6.58	(c)
Oil/Bbl	$60.43	$83.86	$56.25		$88.07	
Depletion expense/Mcfe	$2.07	$2.58	$2.08		$2.40	

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids
(c) Does not include the negative revenue impacts of a $1.2 million and $2.1 million royalty settlement accrual through September 30, 2009 and 2008, respectively, resulting in a $0.17/Mcf and $0.27/Mcf price impact

The following are summaries of LOE/Mcfe:

	Three Months Ended September 30, 2009			Three Months Ended September 30, 2008		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$1.47	$0.31	$1.78	$1.62	$0.25	$1.87
Colorado	1.07	0.41	1.48	1.22	0.71	1.93
Wyoming	1.29	—	1.29	1.21	—	1.21
All other properties	0.83	0.13	0.96	0.71	0.12	0.83
All locations	$1.24	$0.20	$1.44	$1.26	$0.20	$1.46

Location	Nine Months Ended September 30, 2009 LOE	Gathering, Compression and Processing	Total	Nine Months Ended September 30, 2008 LOE	Gathering, Compression and Processing	Total
New Mexico	$1.29	$0.28	$1.57	$1.51	$0.29	$1.80
Colorado	1.02	0.41	1.43	1.17	0.80	1.97
Wyoming	1.41	—	1.41	1.54	—	1.54
All other properties	0.83	0.27	1.10	0.89	0.10	0.99
All locations	$1.19	$0.22	$1.41	$1.33	$0.21	$1.54

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008. Income from continuing operations decreased $1.7 million for the three months ended September 30, 2009 compared to the same period in 2008 primarily due to:

· Revenue decreased $7.6 million due to a 28% decrease in the average hedged price of oil received, a 14% decrease in average hedged price of gas received, and a 10% decrease in production of gas and a 4% decrease in production of oil. The gas production decrease reflects our decision to shut-in production at properties with the highest operating costs, impact of normal production declines, and lower levels of capital spending than in prior periods. Shut-ins reduced production for the three months ended September 30, 2009 by approximately 0.2 Bcfe.

Partially offsetting these were the following:

· Decreased depletion and depreciation expense of $2.3 million primarily reflecting a reduced depletion rate caused by a lower asset base resulting from previous asset impairment charges and commodity price impacts on oil and gas reserve quantities; and

· A $2.2 million decrease in production taxes reflecting lower commodity prices.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008. Income from continuing operations decreased $37.0 million for the nine months ended September 30, 2009 compared to the same period in 2008 primarily due to:

- A $27.8 million after-tax non-cash ceiling test impairment charge for the quarter ended March 31, 2009 due to a ceiling test valuation of our natural gas and crude oil properties resulting from low quarter-end natural gas prices. The write-down of gas and oil properties was based on March 31, 2009 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; and

- A $33.5 million decrease in revenue due to a 36% decrease in the average hedged price of oil received, a 33% decrease in average hedged price of gas received, a 4% decrease in oil production and a 5% decrease in gas production. The gas production decrease reflects our decision to shut-in production at properties with the highest operating costs, the impact of normal production declines and lower levels of capital spending than in prior periods. Shut-ins reduced production for the nine months ended September 30, 2009 by approximately 0.4 Bcfe.

Partially offsetting these were the following:

- A $1.9 million decrease in LOE as compared to 2008 due to cost reduction efforts;

- A $7.3 million decrease in production taxes reflecting lower commodity prices; and

- A $3.8 million income tax benefit related to an adjustment of a previously recorded tax position.

Coal Mining

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue	$15,187	$16,031	$43,082	$41,925
Operating expenses	14,167	14,210	42,836	38,556
Operating income	$1,020	$1,821	$246	$3,369
Income from continuing operations and net income available for common stock	$2,256	$1,092	$2,575	$3,217

The following table provides certain operating statistics for our Coal Mining segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Tons of coal sold	1,591	1,521	4,460	4,518
Cubic yards of overburden moved	4,187	3,368	10,822	9,021

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008.
Income from continuing operations from our Coal Mining segment for the three months ended September 30, 2009 increased $1.2 million compared to the same period in the prior year. Results were impacted by the following:

- A $2.1 million increase from rental income from a recently entered into lease agreement associated with the mine property site leased to the owners of Wygen III. The agreement provides for a March 2008 start date reflecting the commencement of construction on Wygen III; and

- Operating expenses were comparable for the three months ended September 30, 2009 to the same period in the prior year primarily due to increases in depreciation expense of $0.8 million due to an increased asset base offsetting decreases in diesel fuel costs of $0.9 million. Cubic yards of overburden moved increased 24%.

Partially offsetting these was the following:

- Revenue decreased $0.8 million, or 5%, for the three month period ended September 30, 2009 primarily due to a decrease in average price received, partially offset by higher volumes sold. The lower average price received includes the impact of sales prices to our regulated utility subsidiaries that are determined in part by a return on investment base.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008.
Income from continuing operations from our Coal Mining segment for the nine months ended September 30, 2009 decreased $0.6 million compared to the same period in the prior year. Results were impacted by the following:

- Operating expenses increased $4.3 million, or 11%, during the nine months ended September 30, 2009 primarily due to increased depreciation expense of $4.6 million due to increased equipment usage and an increased asset base, and increased coal taxes of $1.2 million due to higher coal prices, partially offset by decreased diesel fuel cost of $1.9 million. Cubic yards of overburden moved increased 20%.

Partially offsetting the increased expenses were the following:

- Revenue increased $1.2 million, or 3%, for the nine month period ended September 30, 2009 compared to the same period in 2008 primarily due to an increase in average price received, partially offset by lower volumes sold. The higher average price received includes the impact of sales prices to our regulated utility subsidiaries that are determined in part by a return on investment base; and

- A $2.4 million increase from rental income associated with the mine property leased to the owners of Wygen III.

Energy Marketing

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)			
Revenue –				
Realized gas marketing gross margin	$262	$(4,477)	$22,617	$3,384
Unrealized gas marketing gross margin	(5,252)	26,889	(12,230)	24,418
Realized oil marketing gross margin	1,525	(1,856)	9,633	2,472
Unrealized oil marketing gross margin	(1,794)	(1,360)	(10,721)	191
	(5,259)	19,196	9,299	30,465
Operating expenses	604	9,026	10,036	19,506
Operating (loss) income	$(5,863)	$10,170	$(737)	$10,959
(Loss) income from continuing operations and net (loss) income available for common stock	$(4,404)	$6,902	$(1,156)	$7,565

The following is a summary of average daily volumes marketed:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Natural gas physical sales – MMBtus	2,206,300	1,854,100	2,013,900	1,749,600
Crude oil physical sales – Bbls	13,300	7,800	12,100	7,300

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008. Income from continuing operations decreased $11.3 million for the three months ended September 30, 2009 compared to the same period in 2008, primarily due to:

· A $32.6 million decrease in unrealized marketing margins. The decrease results from the market circumstances that produced a substantial mark-to-market gain in the third quarter of the prior year.

Partially offsetting this decrease were the following:

· An $8.1 million increase in realized marketing margins primarily due to higher volumes and margin. In addition, gross margins from crude oil were higher due to the impact of increased volumes marketed; and

· Lower operating expenses of $8.4 million primarily due to lower provision for incentive compensation expense.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008. Income from continuing operations decreased $8.7 million for the nine months ended September 30, 2009 compared to the same period in 2008, primarily due to:

· A $4.7 million decrease in unrealized marketing margins; and

· Lower operating expenses of $9.5 million primarily due to lower provision for incentive compensation expenses.

Partially offsetting these decreases was the following:

· A $26.4 million increase in realized marketing margins primarily due to higher volumes and margin. In addition, gross margins from crude oil were higher due to the impact of increasing commodity prices and increased volumes marketed.

Power Generation

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Revenue	$7,538	$11,704	$22,372	$29,079
Operating expense (gains)	3,890	4,338	(13,888)	18,877
Operating income	$3,648	$7,366	$36,260	$10,202
Income from continuing operations	$575	$3,197	$18,487	$1,828

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Contracted power plant fleet availability:				
Coal-fired plant	98.7%	96.8%	95.6%	95.6%
Natural gas-fired plants	99.7%	99.4%	98.8%	93.6%
Total availability	99.1%	97.8%	96.9%	94.8%

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008. Income from continuing operations decreased $2.6 million for the three months ended September 30, 2009 compared to the same period in 2008, and was primarily impacted by:

· The sale of excess emission credits in 2008 for $2.7 million resulting from the decommissioning of the Ontario facility;

· A decrease of $0.8 million reflecting the net earnings impact of replacing MEAN's 20 MW power purchase agreement with operating and site lease agreements related to their purchase of a 23.5% ownership interest in Wygen I; and

· An increase of $0.5 million in net interest expense related to intersegment debt restructuring.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008. Income from continuing operations increased $16.7 million for the nine months ended September 30, 2009 compared to the same period in 2008, and was primarily impacted by:

· A $16.9 million after-tax gain on the sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility. In conjunction with the sale, MEAN will make payments for costs associated with coal supply, plant operations and administrative services. In addition, a 10-year power purchase contract under which MEAN was obligated to buy from us 20 MW of power annually was terminated; and

· 2008 results reflect $11.8 million of allocated indirect corporate costs and inter-segment net interest expense related to the IPP assets sold and not reclassified to discontinued operations.

Partially offsetting were the following:

· A decrease of $2.9 million reflecting the net earnings impact of replacing MEAN's 20 MW power purchase agreement with operating and site lease agreements related to their purchase of a 23.5% ownership interest in Wygen I;

· An $8.5 million increase in net interest expense primarily due to a change in inter-segment debt to equity capital structure; and

· The sale of excess emission credits in 2008 for $2.7 million resulting from the decommissioning of the Ontario facility.

Corporate

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008. Loss from continuing operations increased $7.0 million primarily due to unrealized net, mark-to-market losses for the quarter ended September 30, 2009 of approximately $5.7 million after-tax on certain interest rate swaps and a $2.1 million after-tax increase in net interest expense. In addition, 2008 results included approximately $0.6 million after-tax for transition and integration costs related to the Aquila Transaction.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008. Income from continuing operations increased $21.1 million primarily due to unrealized net, mark-to-market gains for the nine months ended September 30, 2009 of approximately $24.6 million after-tax on certain interest rate swaps, partially offset by a $9.1 million after-tax increase in net interest expense. In addition, 2008 results include $4.2 million after-tax for transition and acquisition costs related to the Aquila Transaction.

Discontinued Operations

Earnings from discontinued operations were $1.7 million and $2.4 million for the three and nine month periods ended September 30, 2009, respectively, compared to $159.5 million for the same period in 2008. The income from discontinued operations in 2009 relates to the working capital and tax adjustments for the IPP Transaction. The income from discontinued operations in 2008 relates primarily to the IPP Transaction with a gain on the sale of $139.7 million.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2008 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 2008 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the nine month period ended September 30, 2009, we generated sufficient cash flow from operations to meet our operating needs, fund a portion of our property, plant and equipment additions and to pay dividends on our common stock. We received proceeds of $51.9 million for the sale of a 23.5% interest in the Wygen I power plant to MEAN and $32.8 million for the sale to MDU of a 25% interest in the 110 MW Wygen III power plant under construction near Gillette, Wyoming. We plan to fund future property and investment additions including our share of the construction costs of the Wygen III power plant and generation for Colorado Electric from internally generated cash resources and external financings.

Cash flows from operations of $270.9 million for the nine month period ended September 30, 2009 represent a $190.8 million increase compared to the same period in the prior year. The increase in cash provided by operating activities for the current period was due to an increase of $1.8 million in our income from continuing operations and changes in working capital as follows:

· A $132.6 million increase in cash flows from working capital changes. This increase primarily resulted from a $70.6 million increase in cash flows from lower materials, supplies and fuel, a $45.5 million increase from lower accounts receivable and other current assets and a $16.5 million increase from lower accounts payable and other current liabilities. Changes in materials, supplies and fuel primarily relate to natural gas held in storage by Energy Marketing and the Gas Utilities which fluctuates based on seasonal trends and economic decisions reflecting current market conditions;

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

· A $71.4 million decrease in cash flows related to changes in deferred income taxes which is primarily a result of the deferred tax liability related to tax planning strategies implemented in connection with the IPP Transaction that occurred in 2008 and the deferred tax benefit associated with a non-cash ceiling test impairment charge applicable to our crude oil and natural gas properties recorded in 2009;

· A $46.5 million increase in cash flows from the net change in derivative assets and liabilities primarily from derivatives associated with normal operations of our gas and oil marketing business and our Oil and Gas segment related to commodity price fluctuations;

· A $21.5 million increase in depreciation, depletion and amortization expense;

· A $43.3 million increase to adjust for the non-cash effect of the ceiling test impairment;

· A $26.0 million decrease to adjust for the non-cash effect of the gain on sale of operating assets. This gain relates to the sale of the 23.5% interest in the Wygen I power plant to MEAN for which we received $51.9 million included in investing activities;

· A $37.8 million decrease to adjust for the non-cash effect of unrealized mark-to-market gains on interest rate swaps; and

- An $84.5 million increase in regulatory assets and liabilities primarily resulting from deferred gas adjustments for our Gas Utilities segment and employee benefit liabilities at our Electric Utilities and Gas Utilities.

During the nine months ended September 30, 2009, we had cash outflows from investing activities of $151.4 million, which were primarily due to the following:

· Cash outflows of $245.1 million for property, plant and equipment additions. These outflows include approximately $35.7 million related to the construction of our Wygen III power plant, approximately $34.1 million at our Gas Utilities primarily for distribution, approximately $20.2 million in oil and gas property maintenance capital and development drilling, and approximately $140.6 million of distribution, transmission and generation at our Electric Utilities, which includes new transmission at Colorado Electric and a plant air condenser upgrade at Black Hills Power;

· Cash inflows of $51.9 million of proceeds from the sale of the 23.5% interest in the Wygen I power plant to MEAN;

· Cash inflows of $32.8 million of proceeds from the sale of the 25% interest in the Wygen III power plant to MDU; and

·Cash inflows of $7.1 million for working capital adjustments on the purchase price allocation of the Aquila Transaction.

During the nine months ended September 30, 2009, we had net cash outflows from financing activities of $150.4 million primarily resulting from:

· $353.3 million outflow for net re-payments on the Corporate Credit Facility and the Acquisition Facility;

· $41.3 million outflow for payments of cash dividends on common stock; and

·$248.5 million inflow from proceeds from issuance of senior unsecured five year notes.

Dividends

Dividends paid on our common stock totaled $41.3 million during the nine months ended September 30, 2009, or $0.355 per share. On October 29, 2009, our Board of Directors declared a quarterly dividend of $0.355 per share payable December 1, 2009, which is equivalent to an annual dividend rate of $1.42 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. As of September 30, 2009, we had approximately $137.7 million of cash unrestricted for operations.

Corporate Credit Facility

Our $525.0 million revolving credit facility expires on May 4, 2010. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 0.95% one-month borrowing rate as of September 30, 2009).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At September 30, 2009, we had borrowings of $350.5 million and $37.7 million of letters of credit issued on our revolving credit facility. Available capacity remaining on our revolving credit facility was approximately $136.8 million at September 30, 2009.

The credit facility includes 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:

· A consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income beginning January 1, 2005;

· A recourse leverage ratio not to exceed 0.65 to 1.00; and

· An interest expense coverage ratio of not less than 2.5 to 1.0.

If these covenants are violated, it would be considered an event of default entitling the lenders to terminate the remaining commitment 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 $20 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.

The credit facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result, after giving effect to such action.

Our consolidated net worth was $1,062.5 million at September 30, 2009, which was approximately $254.0 million in excess of the net worth we were required to maintain under the credit facility. At September 30, 2009, our long-term debt ratio was 40.4%, our total debt leverage ratio (long-term debt and short-term debt) was 50.9%, and our recourse leverage ratio was approximately 55.2%. Our interest expense coverage ratio for the twelve month period ended September 30, 2009 was 3.7 to 1.0.

Enserco Credit Facility

On May 8, 2009, Enserco entered into an agreement for a $240 million committed credit facility. Societe Generale, Fortis Capital Corp., and BNP Paribas were co-lead arranger banks. On May 27, 2009, Enserco entered into an agreement for an additional $60 million of commitments under the credit facility with three participating banks: Calyon, Rabobank and RZB Finance. This credit facility expires on May 7, 2010. The facility is a borrowing base line of credit, which allows for the issuance of letters of credit and for borrowings. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds. At September 30, 2009, $71.7 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

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, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries.

Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of September 30, 2009, the restricted net assets at our Electric and Gas Utilities were approximately $79.2 million.

In August 2009, one of the covenants to the Enserco Credit Facility was amended to temporarily increase the allowable rolling twelve month Net Cumulative Loss as calculated on a Non-GAAP basis and temporarily restrict all dividends or loans to the Company. In addition to the borrowing base structure which requires Enserco to maintain certain levels of tangible net worth and net working capital, 100% of Enserco's net assets are now restricted. The Company expects this to be the case through November 30, 2009. Therefore, upon review of these covenants at September 30, 2009, restricted net assets at Enserco total $214.3 million for this stand-alone Enserco Credit Facility.

Acquisition Facility

In July 2008, in conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under our $1 billion bridge acquisition credit facility dated May 7, 2007. The Acquisition Facility was structured as a single-draw term loan facility for the sole purpose of financing the Aquila Transaction.

On April 9, 2009, we received proceeds of $30.2 million for the sale of 25% of the Wygen III plant to MDU. The net proceeds were used to pay down a portion of the Acquisition Facility.

On May 14, 2009, we received proceeds from a $250 million public debt offering. The net proceeds were used to pay down a portion of the Acquisition Facility.

On June 15, 2009, we paid off the remaining $104.6 million balance of the Acquisition Facility by borrowing on our Corporate Credit Facility.

Public Debt Offering

On May 14, 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds of $248.5 million, net of underwriting fees. Proceeds were used to pay down the Acquisition Facility. Deferred financing costs related to the offering of $2.3 million were capitalized and will be amortized over the life of the notes.

Black Hills Power Bond Issuance

On October 27, 2009, our regulated utility, Black Hills Power, completed a $180 million first mortgage bond issuance. The bonds were priced at 99.931% of par and a reoffer yield of 6.13%. The bonds mature November 1, 2039 and carry an annual interest rate of 6.125%, which will be paid semi-annually. We received proceeds of $178.3 million net of underwriting fees, which were used to repay borrowings under the Corporate Credit Facility. Estimated deferred finance costs of $1.9 million were capitalized and will be amortized over the life of the bonds.

Future Financing Plans

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

We continue to evaluate the debt capital markets and prepare for additional long-term debt issuances to refinance other short-term debt and fund our power generation construction projects.

In the unlikely event we are unable to complete debt financing on acceptable terms, we will consider implementing alternative measures to conserve or raise capital. These alternatives could include deferring our planned capital expenditure program, implementing asset sales, issuing equity, reducing or eliminating our dividend payments, or curtailing certain business activities, including our marketing operations.

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations.

We have interest rate swaps with a notional amount of $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. For the three months ended September 30, 2009, we recorded an $8.7 million pre-tax unrealized mark-to-market non-cash loss and for the nine months ended September 30, 2009, we recorded a $37.8 million pre-tax unrealized mark-to-market non-cash gain on the swaps. The mark-to-market value on these swaps was a liability of $56.7 million at September 30, 2009. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of ten and twenty years and have amended mandatory early termination dates ranging from December 15, 2009 to December 15, 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 term of 7.25 years. These swaps have been designated as cash flow hedges and accordingly, their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $19.5 million at September 30, 2009.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2008 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 September 30, 2009, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

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

In addition, the first mortgage bonds issued by Black Hills Power were rated at September 30, 2009 as follows:

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

In August 2009, Moody’s upgraded the senior secured debt rating for Black Hills Power to A3.

Capital Requirements

During the nine months ended September 30, 2009, capital expenditures were approximately $245.1 million for property, plant and equipment additions, which were partially financed through approximately $31.2 million of accrued liabilities. We currently expect total capital expenditures in 2009 to approximate $340.7 million. This sum includes, but is not limited to: $62.1 million for our share of the Wygen III power plant located near Gillette, Wyoming in which we retain a 75% ownership interest; $62.9 million related to growth and maintenance capital for our Black Hills Energy utility properties, and $25.0 million within our Oil and Gas segment primarily for maintenance capital and development drilling.

Actual and forecasted capital requirements for maintenance capital and development capital are as follows:

	Nine Months Ended September 30, 2009 Expenditures	Total 2009 Planned Expenditures	Total 2010 Planned Expenditures	Total 2011 Planned Expenditures
	(in thousands)			
Utilities:				
Electric Utilities – Wygen III(1)	$35,700	$62,100	$12,600	$—
Electric Utilities (2) (3)	143,037	157,400	256,900	259,400
Gas Utilities	33,907	39,600	56,450	56,070
Non-regulated Energy:				
Oil and Gas(4)	20,243	25,000	38,340	63,810
Power Generation(5)	4,452	30,242	82,690	147,820
Coal Mining	6,792	13,160	17,630	17,260
Energy Marketing	128	811	400	—
Corporate	855	12,340	16,290	10,400
	$245,114	$340,653	$481,300	$554,760

(1) Actual and forecasted expenditures for the Wygen III coal-fired plant reflect our 75% ownership interest in the plant.

(2) Electric Utilities capital requirements include approximately $22.3 million for transmission projects in 2009.

(3) The 2009 total planned expenditures include capital requirements associated with our plans to build gas-fired power generation facilities to serve our Colorado Electric customers. In February 2009, the CPUC authorized Colorado Electric to build two natural gas-fired combustion turbine facilities. We expect to spend capital of $47.9 million in 2009 particularly related to the commitment to purchase the turbine generators from GE. The total construction cost is expected to be approximately $225 million to $275 million to be completed by the end of 2011. The mid-point of this estimate is included in the forecast above.

(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 could further reduce 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 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 $26.5 million in 2009. The mid-point of this estimate is included in the forecast above.

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

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment decreased $0.3 million from $93.5 million at December 31, 2008 to $93.2 million at September 30, 2009. Approximately $56.3 million of the firm transportation and storage fee obligations relate to the 2009-2011 period with the remaining occurring thereafter.

In June 2009, we entered into a ten and a half year lease obligation to relocate our office located in Golden, Colorado to Denver, Colorado. Total obligations over the ten and a one-half year lease are $14.7 million. This lease contained certain landlord incentives including rent abatement, relocation and tenant finishes.

Guarantees

See Note 7 to our Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

New Accounting Pronouncements

Other than the new pronouncements reported in our 2008 Annual Report on Form 10-K filed with the SEC and those discussed in Notes 2 and 3 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that affect us.

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," "estim "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The forward-looking statements include the factors discussed above, the risk factors described in Item 1A. of our 2008 Annual Report on Form 10-K previously filed with the SEC, and other reports that we file with the SEC from time to time, and the following:

· We are evaluating financing options including 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 million and $7.7 million for the remainder of 2009 and for 2010, 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.

· 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, sustainable deterioration of the market value of our common stock.

§ Negative regulatory orders or other events that materially impact our Utilities' ability to generate stable cash flow over an extended period of time.

· We expect to make approximately $340.7 million, $481.3 million and $554.8 million of capital expenditures in 2009, 2010 and 2011, respectively. 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. A continued decline in crude oil and natural gas prices may cause us to change our planned capital expenditures related to our oil and gas operations.

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

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

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

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

	September 30, 2009	December 31, 2008	September 30, 2008
Net derivative assets (liabilities)	$3,210	$(7,444)	$9,424
Cash collateral	1,840	8,744	12,750
	$5,050	$1,300	$22,174

Non Regulated Trading Activities

The following table provides a reconciliation of activity in our natural gas and crude oil marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the nine months ended September 30, 2009 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2008	$28,447	(a)
Net cash settled during the period on positions that existed at December 31, 2008	(34,477)	
Unrealized gain on new positions entered during the period and still existing at September 30, 2009	5,423	
Realized gain on positions that existed at December 31, 2008 and were settled during the period	(4,563)	
Change in cash collateral	21,144	
Unrealized gain on positions that existed at December 31, 2008 and still exist at September 30, 2009	10,646	
Total fair value of energy marketing positions at September 30, 2009	$26,620	(a)

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

	September 30, 2009	June 30, 2009	March 31, 2009	December 31, 2008
Net derivative assets	$23,054	$32,352	$39,843	$54,117
Cash collateral	4,829	9,267	(3,673)	(16,315)
Market adjustment recorded in material, supplies and fuel	(1,263)	(3,815)	(2,399)	(9,355)
	$26,620	$37,804	$33,771	$28,447

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in ASC 820. See Note 3 of the Notes to Consolidated Financial Statements in our 2008 Annual Report on Form 10-K and Note 12, 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	$4,829	$—	$4,829
Level 2	15,893	3,845	19,738
Level 3	3,375	(59)	3,316
Market value adjustment for inventory (see footnote (a) above)	(1,263)	—	(1,263)
Total fair value of our energy marketing positions	$22,834	$3,786	$26,620

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative under ASC 815. Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas and crude oil marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting standards for derivatives generally does not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our energy marketing positions are fully economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements. The table below references non-GAAP measures that quantify these positions.

The following table presents a reconciliation of our September 30, 2009 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)	$26,620
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	(4,556)
Fair value of all forward positions (non-GAAP)	22,064
Cash collateral included in GAAP marked-to-market fair value	(4,829)
Fair value of all forward positions excluding cash collateral (non-GAAP) *	$17,235

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

There have been no material changes in market risk compared to those reported in our 2008 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 2008 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 2009, 2010 and 2011 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
AECO	09/07/2007	Swap	04/08 – 10/09	1,000	$6.89
San Juan El Paso	10/29/2007	Swap	10/09 – 12/09	5,000	$7.53
CIG	10/29/2007	Swap	10/09 – 12/09	1,500	$7.07
NWR	11/16/2007	Swap	01/09 – 12/09	1,500	$6.87
San Juan El Paso	12/13/2007	Swap	10/09 – 12/09	1,500	$7.39
San Juan El Paso	12/13/2007	Swap	10/09 – 12/09	1,500	$7.41
CIG	01/03/2008	Swap	01/10 – 03/10	2,000	$7.49
NWR	01/03/2008	Swap	01/10 – 03/10	1,500	$7.50
AECO	01/03/2008	Swap	11/09 – 03/10	1,000	$8.07
San Juan El Paso	01/23/2008	Swap	01/10 – 03/10	5,000	$7.50
San Juan El Paso	02/28/2008	Swap	01/10 – 03/10	3,000	$8.55
San Juan El Paso	04/09/2008	Swap	04/10 – 06/10	5,000	$7.26
San Juan El Paso	04/30/2008	Swap	04/10 – 06/10	2,500	$7.65
AECO	08/20/2008	Swap	04/10 – 06/10	1,000	$7.73
San Juan El Paso	08/20/2008	Swap	07/10 – 09/10	5,000	$7.74
AECO	08/20/2008	Swap	07/10 – 09/10	1,000	$7.88
AECO	10/24/2008	Swap	10/10 – 12/10	1,000	$7.05
San Juan El Paso	12/19/2008	Swap	10/09 – 12/09	1,000	$5.12
San Juan El Paso	12/19/2008	Swap	04/10 – 06/10	1,500	$5.39
San Juan El Paso	12/19/2008	Swap	07/10 – 09/10	3,000	$5.95
San Juan El Paso	12/19/2008	Swap	10/10 – 12/10	5,000	$5.89
CIG	01/26/2009	Swap	04/10 – 06/10	2,000	$4.45
CIG	01/26/2009	Swap	07/10 – 09/10	2,000	$4.47
CIG	01/26/2009	Swap	10/10 – 12/10	2,000	$4.68
CIG	01/26/2009	Swap	01/11 – 03/11	2,000	$6.00
NWR	01/26/2009	Swap	01/11 – 03/11	2,000	$6.05
San Juan El Paso	01/26/2009	Swap	01/11 – 03/11	5,000	$6.38
San Juan El Paso	02/13/2009	Swap	01/11 – 03/11	2,500	$6.16
San Juan El Paso	02/13/2009	Swap	10/10 – 12/10	3,000	$5.35
NWR	02/13/2009	Swap	04/10 – 12/10	1,000	$4.20
AECO	03/04/2009	Swap	01/11 – 03/11	1,000	$5.95
NWR	03/04/2009	Swap	04/10 – 06/10	1,000	$4.06
NWR	03/04/2009	Swap	07/10 – 09/10	1,000	$4.12
NWR	03/04/2009	Swap	10/10 – 12/10	1,000	$4.55
NWR	03/20/2009	Swap	01/10 – 03/10	500	$4.58
San Juan El Paso	03/20/2009	Swap	01/10 – 03/10	1,000	$4.87
San Juan El Paso	06/02/2009	Swap	04/11 – 06/11	5,000	$5.99
San Juan El Paso	06/02/2009	Swap	10/09 – 12/09	1,500	$4.14
AECO	06/02/2009	Swap	04/11 – 06/11	800	$5.89
NWR	06/02/2009	Swap	10/09 – 12/09	500	$3.95

NWR	06/02/2009	Swap	04/11 – 06/11	1,500	$5.54
San Juan El Paso	06/25/2009	Swap	04/11 – 06/11	2,500	$5.55
CIG	06/25/2009	Swap	04/11 – 06/11	1,750	$5.33
CIG	09/02/2009	Swap	07/11 – 09/11	500	$5.32
NWR	09/02/2009	Swap	07/11 – 09/11	500	$5.32

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	09/02/2009	Swap	07/11 – 09/11	2,500	$5.54
CIG	09/25/2009	Swap	07/11 – 09/11	500	$5.59
NWR	09/25/2009	Swap	07/11 – 09/11	1,000	$5.59
AECO	09/25/2009	Swap	07/11 – 09/11	500	$5.76
San Juan El Paso	09/25/2009	Swap	07/11 – 09/11	5,000	$5.91
San Juan El Paso	10/09/2009	Swap	01/10 – 03/10	2,000	$5.42
San Juan El Paso	10/09/2009	Swap	04/10 – 06/10	750	$5.29
San Juan El Paso	10/09/2009	Swap	07/10 – 09/10	1,000	$5.65
San Juan El Paso	10/09/2009	Swap	10/10 – 12/10	1,000	$5.90
San Juan El Paso	10/23/2009	Swap	10/11 – 12/11	2,500	$6.23
NWR	10/23/2009	Swap	10/11 – 12/11	1,500	$6.12
San Juan El Paso	10/23/2009	Swap	01/11 – 03/11	1,000	$6.59

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	10/29/2007	Put	10/09 – 12/09	5,000	$75.00
NYMEX	10/29/2007	Swap	10/09 – 12/09	5,000	$80.75
NYMEX	11/16/2007	Put	10/09 – 12/09	5,000	$75.00
NYMEX	01/03/2008	Put	01/10 – 03/10	5,000	$80.00
NYMEX	01/03/2008	Swap	01/10 – 03/10	5,000	$88.70
NYMEX	01/23/2008	Swap	10/09 – 12/09	5,000	$83.10
NYMEX	01/23/2008	Swap	01/10 – 03/10	5,000	$82.90
NYMEX	02/28/2008	Put	01/10 – 03/10	5,000	$85.00
NYMEX	04/09/2008	Swap	04/10 – 06/10	5,000	$99.60
NYMEX	04/30/2008	Put	04/10 – 06/10	5,000	$85.00
NYMEX	05/29/2008	Put	04/10 – 06/10	5,000	$105.00
NYMEX	07/16/2008	Swap	04/10 – 06/10	5,000	$135.10
NYMEX	07/16/2008	Swap	07/10 – 09/10	5,000	$134.90
NYMEX	08/20/2008	Put	07/10 – 09/10	5,000	$90.00
NYMEX	09/03/2008	Put	07/10 – 09/10	5,000	$90.00
NYMEX	10/24/2008	Put	07/10 – 09/10	5,000	$60.00
NYMEX	12/05/2008	Swap	10/10 – 12/10	5,000	$65.20
NYMEX	01/26/2009	Swap	10/10 – 12/10	5,000	$60.15
NYMEX	01/26/2009	Swap	01/11 – 03/11	5,000	$60.90
NYMEX	02/13/2009	Swap	01/11 – 03/11	5,000	$60.05
NYMEX	03/04/2009	Swap	10/10 – 12/10	5,000	$55.80
NYMEX	03/04/2009	Swap	01/11 – 03/11	5,000	$57.00
NYMEX	04/08/2009	Swap	04/11 – 06/11	5,000	$68.80
NYMEX	04/23/2009	Swap	04/11 – 06/11	5,000	$65.10
NYMEX	06/02/2009	Swap	10/10 – 12/10	5,000	$74.30
NYMEX	06/02/2009	Swap	01/11 – 03/11	5,000	$75.05
NYMEX	06/02/2009	Swap	04/11 – 06/11	5,000	$75.86
NYMEX	06/04/2009	Put	04/11 – 06/11	5,000	$67.00
NYMEX	09/02/2009	Swap	07/11 – 09/11	5,000	$75.10
NYMEX	09/02/2009	Put	07/11 – 09/11	5,000	$63.00
NYMEX	09/29/2009	Swap	07/11 – 09/11	5,000	$74.00
NYMEX	10/06/2009	Put	07/11 – 09/11	5,000	$65.00
NYMEX	10/09/2009	Swap	10/11 – 12/11	5,000	$79.35
NYMEX	10/23/2009	Put	10/11 – 12/11	5,000	$75.00

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of September 30, 2009. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

There have been no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2009 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 18 in Item 8 of our 2008 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

Item 1A. Risk Factors

Except to the extent updated or described below, our Risk Factors are documented in Item IA. of Part I in our Annual Report on Form 10-K for the year ended December 31, 2008.

Federal and state laws concerning climate change and air emissions, including emission reduction mandates 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.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, Colorado and Idaho. We are constructing another fossil-fuel generating plant in Wyoming. Air emissions of fossil-fuel generating plants are subject to federal, state and tribal regulation. Recent developments under federal and state laws and regulation governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations.

On April 2, 2007, the U.S. Supreme Court issued a decision in the case of Massachusetts v. U.S. Environmental Protection Agency, holding that CO2 and other GHG emissions are pollutants subject to regulation under the motor vehicle provisions of the Clean Air Act. The case was remanded to the EPA for further rulemaking to determine whether GHG emissions may reasonably be anticipated to endanger public health or welfare, or alternatively, to explain why GHG emissions should not be regulated. On April 17, 2008, the EPA issued its proposed endangerment finding under Section 202 of the Clean Air Act. Although this proposal does not specifically address stationary sources, such as power generation plants, the general endangerment finding relative to GHG's could support such a proposal by the EPA for stationary sources. On March 10, 2009, the EPA released proposed rules regarding a mandatory GHG reporting regimen, the purpose of which would be to collect data to inform future policy and regulatory decisions. Finally, federal legislation is currently under consideration in the U.S. Congress, including H.R. 2454, "the American Clean Energy and Security Act of 2009", which was approved by the U.S. House of Representatives on June 26, 2009. This legislation would affect electric generation and electric and natural gas distribution companies. H.R. 2454 would establish mandatory GHG reduction targets, utilizing a Federal emissions cap-and-trade program. H.R.2454 also proposes a national renewable electricity standard, which would implement a phased process ultimately mandating that 20% of electricity sold by retail suppliers be met by energy efficiency improvements and renewable energy resources by 2020. The Senate is expected to consider its own version of the legislation later in 2009 or in 2010.

In addition, the EPA published in the October 27, 2009 Federal Register a proposed rule that would tailor the major source applicability thresholds for GHG emissions under the Prevention of Significant Deterioration (PSD) and Title V programs of the Clean Air Act and set a PSD significance level for GHG emissions. EPA states this rule is necessary because they expect to soon promulgate regulations under the Clean Air Act to control GHG emissions and as a result, trigger PSD and Title V applicability requirements. This proposed rule would phase in the applicability thresholds for both the PSD and Title V programs for sources of GHG emissions. The first phase, which would last 6 years, would establish a temporary level for the PSD and Title V applicability thresholds at 25,000 tons per year on a carbon dioxide equivalent basis and would also establish temporary PSD significance levels. All our generating units would exceed this threshold and if the pending rule to control GHG emissions is published and finalized, we would be required upon Title V permit renewal, to evaluate options for reducing GHG emissions, to possibly include a Best Available Control Technology review that could result in more stringent emissions control practices and technologies. In the second phase of this proposed rule, EPA would within 5 years of the rule being final, review the first phase and promulgate revised applicability and significance level thresholds as appropriate.

Due to the uncertainty as to the final outcome of federal climate change legislation, or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation upon our company will depend upon many factors, including but not limited to the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level, and the availability of technologies to control or reduce GHG emissions. If a “cap and trade” structure is implemented, the impact will also be affected by the degree to which offsets are allowed, the allocation of emission allowances to specific sources, and the affect of carbon regulation on natural gas and coal prices.

More stringent GHG emissions limitations or other energy efficiency requirements, however, could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base, we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by our non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

We own electric utilities that serve customers in Colorado, Montana, South Dakota and Wyoming. To varying degrees, Colorado and Montana have each adopted mandatory renewable portfolio standards that require electric utilities to supply a minimum percentage of the power delivered to customers from renewable resources (e.g., wind, solar, biomass) by a certain date in the future. These renewable energy portfolio standards have increased the power supply costs of our electric operations. If these states increase their renewable energy portfolio standards, or if similar standards are imposed by the other states in which we operate electric utilities, our power supply costs will further increase. Although we will seek to recover these higher costs in rates, any unrecovered costs could have a material negative impact on our results of operations and financial condition.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2009 – July 31, 2009	143	$22.99	—	—
August 1, 2009 – August 31, 2009	3,551	$26.48	—	—
September 1, 2009 – September 30, 2009	—	$—	—	—
Total	3,694	$26.34	—	—

(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	Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon, as Trustee to Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (previously filed as Exhibit 4.21 to the Company's Post-Effective Amendment No. 2 to the Registration Statement on Form S-3 (File No. 333-150669) and incorporated by reference herein).
Exhibit 10	First Amendment to Third Amended and Restated Credit Agreement effective August 25, 2009, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, Societe Generale, BNP Paribas, and each of the other financial institutions which are parties thereto.
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002.

BLACK HILLS CORPORATION

Signatures

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

BLACK HILLS CORPORATION

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

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

Dated: November 9, 2009

EXHIBIT INDEX

Exhibit Number	Description
Exhibit 4	Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon, as Trustee to Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (previously filed as Exhibit 4.21 to the Company's Post-Effective Amendment No. 2 to the Registration Statement on Form S-3 (File No. 333-150669) and incorporated by reference herein).
Exhibit 10	First Amendment to Third Amended and Restated Credit Agreement effective August 25, 2009, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, Societe Generale, BNP Paribas, and each of the other financial institutions which are parties thereto.
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.