BLACK HILLS CORP /SD/
Form 10-Q
November 10, 2008

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, 2008.

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

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

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

Yes o No x

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

Class	Outstanding at October 31, 2008
Common stock, $1.00 par value	38,450,217 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:

AFUDC	Allowance for Funds Used During Construction
ARB	Accounting Research Bulletin
ARB 51	ARB 51 Consolidated Financial Statements
Aquila	Aquila, Inc.
Aquila Transaction	The 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
BHEP	Black Hills Exploration and Production, Inc., 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 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
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel & Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel & 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
CPUC	Colorado Public Utility Commission
CT	Combustion turbine
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
EITF 87-24	EITF 87-24, Allocation of Interest to Discontinued Operations
Enserco	Enserco Energy Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
FASB	Financial Accounting Standards Board
FSP	FASB Staff Position
FSP FAS 157-1	FSP FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements that Address Fair Value Measurement for Purposes of Lease Classification or Measurement under Statement 13
FSP FAS 157-2	FSP FAS 157-2, Effective Date of FASB Statement No. 157

FSP FIN 39-1	FSP FIN 39-1, Amendment of FASB Interpretation No. 39
FERC	Federal Energy Regulatory Commission
FIN 39	FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts an Interpretation of APB Opinion No. 10 and FASB Statement No. 105
GAAP	Generally Accepted Accounting Principles
Hastings	Hastings Funds Management Ltd
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
Indeck	Indeck Capital, Inc.
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	The July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IUB	Iowa Utility 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
Las Vegas I	Las Vegas I gas-fired power plant
Las Vegas II	Las Vegas II gas-fired power plant
LVC	Las Vegas Cogeneration Limited Partnership, a former subsidiary of Black Hills Non-regulated Holdings that was sold as part of our IPP Transaction
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
Moody s	Moody s Investor Services, Inc.
MW	Megawatt
MWh	Megawatt-hour
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Nebraska gas utility properties acquired from Aquila
Nevada Power	Nevada Power Company
NPSC	Nebraska Public Service Commission
PNM	PNM Resources, Inc.
PUCN	Public Utilities Commission of Nevada
SEC	U. S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 13	SFAS 13, Accounting for Leases
SFAS 71	SFAS 71, Accounting for the Effects of Certain Types of Regulation

SFAS 133	SFAS 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 141(R)	SFAS 141(R), Business Combinations
SFAS 144	SFAS 144, Accounting for the Impairment or Disposal of Long-lived Assets
SFAS 157	SFAS 157, Fair Value Measurements
SFAS 159	SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities
SFAS 160	SFAS 160, Non-controlling Interest in Consolidated Financial Statements an amendment of ARB 51
SFAS 161	SFAS 161, Disclosure about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133
S&P	Standard & Poor s Rating Services
Valencia	Valencia Power, LLC, a former subsidiary of Black Hills Non-regulated Holdings that was sold as part of our IPP Transaction
VIE	Variable Interest Entity
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, LLC

BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008		2007		2008		2007	
	(in thousands, except per share amounts)							
Operating revenues	$	291,892	$	130,167	$	598,015	$	421,190
Operating expenses:								
Fuel and purchased power		131,300		39,127		230,643		119,544
Operations and maintenance		34,477		17,210		80,762		50,272
Administrative and general		40,993		26,272		90,273		76,590
Depreciation, depletion and amortization		30,825		19,333		70,999		53,647
Taxes, other than income taxes		11,609		7,113		31,590		24,691
Impairment of long-lived assets				2,721				2,721
		249,204		111,776		504,267		327,465
Operating income		42,688		18,391		93,748		93,725
Other income (expense):								
Interest expense		(16,402)		(6,093)		(35,160)		(18,652)
Interest income		628		980		1,427		2,396
Allowance for funds used during construction equity		1,390		811		2,287		3,851
Other income, net		171		73		573		396
		(14,213)		(4,229)		(30,873)		(12,009)
Income from continuing operations before equity in earnings of unconsolidated subsidiaries, minority interest and income taxes		28,475		14,162		62,875		81,716
Equity in earnings of unconsolidated subsidiaries		1,359		574		3,656		2,092
Minority interest				(97)		(130)		(285)
Income tax expense		(10,312)		(3,510)		(21,989)		(26,025)
Income from continuing operations		19,522		11,129		44,412		57,498
Income from discontinued operations, net of taxes		145,389		6,335		159,486		17,518
Net income	$	164,911	$	17,464	$	203,898	$	75,016
Weighted average common shares outstanding:								
Basic		38,307		37,643		38,145		36,810
Diluted		38,425		38,078		38,430		37,226
Earnings per share:								
Basic								
Continuing operations	$	0.51	$	0.30	$	1.16	$	1.56
Discontinued operations		3.79		0.17		4.18		0.48
Total	$	4.30	$	0.47	$	5.34	$	2.04
Diluted								
Continuing operations	$	0.51	$	0.29	$	1.16	$	1.55
Discontinued operations		3.78		0.17		4.15		0.47
Total	$	4.29	$	0.46	$	5.31	$	2.02
Dividends paid per share of common stock	$	0.35	$	0.34	$	1.05	$	1.02

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, 2008	December 31, 2007*	September 30, 2007*
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 152,457	$ 76,889	$ 76,407
Restricted cash	5,514	5,443	5,394
Short-term investments	6,310		
Receivables (net of allowance for doubtful accounts of $6,077; $4,588 and $5,259, respectively)	227,862	268,462	217,900
Materials, supplies and fuel	173,734	88,580	85,155
Derivative assets	84,758	35,921	31,896
Deferred income taxes		4,512	
Other assets	32,424	12,698	10,731
Assets of discontinued operations	322	573,601	565,943
	683,381	1,066,106	993,426
Investments	21,911	19,216	23,886
Property, plant and equipment	2,615,627	1,846,565	1,800,625
Less accumulated depreciation and depletion	(566,191)	(509,187)	(500,872)
	2,049,436	1,337,378	1,299,753
Other assets:			
Derivative assets	1,500	2,492	2,746
Goodwill	400,959	11,482	12,076
Other	69,512	32,960	32,346
	471,971	46,934	47,168
	$ 3,226,699	$ 2,469,634	$ 2,364,233
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 234,647	$ 239,177	$ 201,313
Accrued liabilities	144,768	100,986	89,952
Derivative liabilities	62,409	39,380	24,904
Deferred income taxes	592		
Notes payable	627,800	37,000	67,500
Current maturities of long-term debt	2,074	130,326	130,523
Accrued income taxes	48,360	833	17,620
Liabilities of discontinued operations	124	91,233	120,000
	1,120,774	638,935	651,812
Long-term debt, net of current maturities	501,277	503,301	401,851
Deferred credits and other liabilities:			
Deferred income taxes	240,654	207,735	191,451
Derivative liabilities	6,792	9,375	2,941
Other	207,841	135,266	143,539
	455,287	352,376	337,931
Minority interest in subsidiaries	132	5,167	5,075
Stockholders equity:			
Common stock equity			
Common stock $1 par value; 100,000,000 shares authorized; Issued 38,490,315; 37,842,221 and 37,802,087 shares, respectively	38,490	37,842	37,802
Additional paid-in capital	580,601	560,475	558,935
Retained earnings	561,102	397,393	386,869
Treasury stock at cost 40,059; 45,916 and 42,935 shares, respectively	(1,419)	(1,347)	(1,219)
Accumulated other comprehensive loss	(29,545)	(24,508)	(14,823)
	1,149,229	969,855	967,564

	$ 3,226,699	$ 2,469,634	$ 2,364,233

* As adjusted (see Note 2)

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

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BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

	Nine Months Ended September 30, 2008	2007*
	(in thousands)	
Operating activities:		
Net income	$ 203,898	$ 75,016
Income from discontinued operations, net of taxes	(159,486)	(17,518)
Income from continuing operations	44,412	57,498
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	70,999	53,647
Net change in derivative assets and liabilities	(26,853)	(10,300)
Deferred income taxes	76,546	10,008
(Undistributed) distributed earnings in associated companies	(1,988)	177
Allowance for funds used during construction equity	(2,287)	(3,851)
Change in operating assets and liabilities:		
Materials, supplies and fuel	(47,382)	24,960
Accounts receivable and other current assets	111,595	23,374
Accounts payable and other current liabilities	(118,369)	9,038
Other operating activities	(44,772)	11,704
Net cash provided by operating activities of continuing operations	61,901	176,255
Net cash provided by operating activities of discontinued operations	18,184	29,476
Net cash provided by operating activities	80,085	205,731
Investing activities:		
Property, plant and equipment additions	(219,350)	(143,316)
Proceeds from sale of business operations	835,316	
Payment for acquisition of net assets, net of cash acquired	(937,606)	
Increase in short-term investments	(6,525)	
Other investing activities	(698)	(3,304)
Net cash used in investing activities of continuing operations	(328,863)	(146,620)
Net cash used in investing activities of discontinued operations	(28,966)	(13,693)
Net cash used in investing activities	(357,829)	(160,313)
Financing activities:		
Dividends paid	(40,189)	(37,068)
Common stock issued	2,611	149,860
Increase (decrease) in short-term borrowings, net	590,800	(78,000)
Long-term debt repayments	(130,276)	(26,286)
Other financing activities	(72)	(585)
Net cash provided by financing activities of continuing operations	422,874	7,921
Net cash used in financing activities of discontinued operations	(73,928)	(9,643)
Net cash provided by (used in) financing activities	348,946	(1,722)
Increase in cash and cash equivalents	71,202	43,696
Cash and cash equivalents:		
Beginning of period	81,255[a]	37,530[c]
End of period	$ 152,457	$ 81,226[b]
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	$ 25,549	$ 56,274
Cash paid during the period for-		
Interest (net of amounts capitalized)	$ 29,748	$ 30,160
Income taxes paid (net of amounts refunded)	$ 2,984	$ 7,627

* As adjusted (see Note 2)
(a) Includes approximately $4.4 million of cash included in the assets of discontinued operations.
(b) Includes approximately $4.8 million of cash included in the assets of discontinued operations.
(c) Includes approximately $5.0 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 2007 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) 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, the Company believes that the footnotes adequately disclose the information presented. These financial statements should be read in conjunction with the financial statements and the notes thereto, included in the Company s 2007 Annual Report on Form 10-K filed with the SEC.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying financial statements reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of the September 30, 2008, December 31, 2007 and September 30, 2007 financial information and are of a normal recurring nature. Some of the Company s operations 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 our gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment s peak and off-peak seasons. The results of operations for the nine months ended September 30, 2008, are not necessarily indicative of the results to be expected for the full year. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

The Company completed its sale of IPP assets on July 11, 2008. For all periods presented, amounts associated with the IPP plants divested in the IPP Transaction have been reclassified as discontinued operations. See Note 16 for additional information.

The Company completed the Aquila Transaction on July 14, 2008. 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 15 for additional information.

As a result of these transactions, the asset and earnings profile of our company have changed significantly. As of June 30, 2008, regulated utilities properties comprised approximately 38 percent of our consolidated assets and generated approximately 45 percent of our revenues for the quarter ending June 30, 2008. As of September 30, 2008, regulated utility properties comprised approximately 66 percent of our consolidated assets and generated approximately 76 percent of our revenues for the quarter ending September 30, 2008. In order to more appropriately reflect the manner in which we are managing our newly acquired businesses, we have changed our business reporting segments relating to our utility businesses. See Note 11 for additional information.

(2) RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

SFAS 157

During September 2006, the FASB issued SFAS 157. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 does not expand the application of fair value accounting to any new circumstances, but applies the framework to other accounting pronouncements that require or permit fair value measurement. The Company applies fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy Marketing and Oil and Gas business segments, interest rate swap instruments, and other miscellaneous derivatives.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. As of January 1, 2008, the Company adopted the provisions of SFAS 157 for all assets and liabilities measured at fair value except for non-financial assets and liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2. As a result of the Company s adoption of SFAS 157, the Company discontinued its use of a liquidity reserve in valuing the total forward positions within its 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 being recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Operating revenues on the accompanying Condensed Consolidated Statements of Income. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with instruments carried at fair value. This additional disclosure is provided in Note 13.

SFAS 159

SFAS 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 was adopted on January 1, 2008 and did not have an impact on the Company s consolidated financial position, results of operations or cash flows.

FSP FAS 157-1

In February 2008, the FASB issued FSP FAS 157-1, which excludes SFAS 13 and other accounting pronouncements that address fair value for purposes of lease classification and measurement under SFAS 13 from SFAS 157 except when applying SFAS 157 to assets acquired and liabilities assumed in a business combination. The Company applied the provisions of FSP FAS 157-1 from the date of initial adoption of SFAS 157 on January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to lease transactions under SFAS 13 except when applying SFAS 157 to business combinations recorded by the Company.

FSP FAS 157-2

In February 2008, the FASB issued FSP FAS 157-2, which permits a one-year deferral of the application of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The Company adopted FSP FAS 157-2 effective January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009. Management is currently evaluating the impact, if any, that the deferred provisions of SFAS 157 will have on the Company s consolidated financial statements.

FSP FIN 39-1

FSP FIN 39-1 amends certain paragraphs of FIN 39 to permit a reporting entity to offset 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 arrangement. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. The Company adopted FSP FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts. The Company applied FSP FIN 39-1 as a change in accounting principle through retrospective application. Each Condensed Consolidated Balance Sheet herein reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when management believes a legal right of offset exists. Accordingly, December 31, 2007 and September 30**,** 2007 amounts have been reclassified to conform to this presentation as follows (in thousands):

December 31, 2007 Balance Sheet Line Description	As Reported for the 2007 10-K	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	As Reported for the September 2008 10-Q
Current assets:				
Receivables	$ 291,189	$ (1,945)	$ (20,782)	$ 268,462
Derivative assets	$ 37,208	$ (1,287)	$	$ 35,921
Current liabilities:				
Accounts payable	$ 242,813	$ (3,232)	$ (404)	$ 239,177

September 30, 2007 Balance Sheet Line Description	As Reported for the September 2007 10-Q	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	As Reported for the September 2008 10-Q
Current assets:				
Receivables	$ 238,662	$ (2,511)	$ (18,251)	$ 217,900
Derivative assets	$ 29,385	$ 2,511	$	$ 31,896
Non-current assets:				
Derivative assets	$ 3,420	$ (674)	$	$ 2,746
Non-current liabilities:				
Derivative liabilities	$ 3,615	$ (674)	$	$ 2,941

The affect on the Cash Flow Statement for 2007 due to the reclassification is as follows (in thousands):

Cash Flow Statement Operating Activities Line Description	As Reported for the September 2007 10-Q	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	As Reported for the September 2008 10-Q
Accounts receivable and other current assets	$ 21,099	$ 2,511	$ (236)	$ 23,374
Net change in derivative assets and liabilities	$ (4,911)	$ (5,389)	$	$ (10,300)
Accounts payable and other current liabilities	$ 4,662	$ 2,878	$ 1,498	$ 9,038

As of December 31, 2007 and September 30, 2007, the Company offset fair value cash collateral receivables and payables against net derivative positions in the amounts of $(1.3) million and $2.5 million, respectively.

(3) RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. This replaces the cost allocation process in SFAS 141, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. SFAS 141(R) applies 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. We expect SFAS 141(R) will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of any acquisitions we consummate after the effective date. If income tax liabilities are settled for an amount other than as previously recorded prior to the adoption of SFAS 141(R), the reversal of any remaining liability will affect goodwill. If such liabilities reverse subsequent to the adoption of SFAS 141(R), such reversals will affect expense including income tax expense in the period of reversal. The Company is assessing the full impact SFAS 141(R) would have on future consolidated financial statements.

SFAS 160

In December 2007, the FASB issued SFAS 160. SFAS 160 amends ARB 51 and requires:

ownership interests in subsidiaries held by parties other than the parent be clearly identified on the consolidated statement of financial position within equity, but separate from the parent s equity;

consolidated net income attributable to the parent and to the non-controlling interest be clearly identified on the face of the consolidated statement of income;

changes in a parent s ownership interest while the parent retains a controlling financial interest be accounted for consistently as equity transactions;

when a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value; and

sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners.

SFAS 160 is effective for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Management does not expect the adoption of SFAS 160 to have a significant effect on the Company s consolidated financial statements.

SFAS 161

In March 2008, the FASB issued SFAS 161, which requires enhanced disclosures about how derivative and hedging activities affect an entity s financial position, financial performance and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company is currently evaluating the impact of adoption of SFAS 161.

(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, 2008	December 31, 2007	September 30, 2007
Materials and supplies	$ 32,565	$ 27,649	$ 28,092
Fuel Electric Utilities	11,497	5,025	7,401
Gas Supply Gas Utilities	74,407		
Gas and oil held by Energy Marketing*	55,265	55,906	49,662
Total materials, supplies and fuel	$ 173,734	$ 88,580	$ 85,155

* As of September 30, 2008, December 31, 2007 and September 30, 2007, market adjustments related to natural gas held by Energy Marketing and recorded in inventory were $(15.1) million, $(9.8) million and $(6.5) million, respectively (see Note 12 for further discussion of Energy Marketing trading activities).

The increase in gas is due to additions of natural gas storage inventory for the gas utilities acquired in July 2008.

The 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 sales date in the future.

(5) NOTES PAYABLE AND LONG-TERM DEBT

Wygen I

During June 2008, the Company repaid the $128.3 million Wygen I project debt. Borrowings on the revolving credit facility were used to fund the repayment.

We had previously been the lessee of the Wygen I Plant under a synthetic lease arrangement and under GAAP we consolidated the plant, the related project debt and all its operating and financial activities into our financial statements. In conjunction with the repayment of the project debt, the synthetic lease structure was terminated and the Company assumed direct ownership of the plant. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

Acquisition Credit Facility

On July 14, 2008, in conjunction with the closing of the Aquila Transaction, the Company borrowed $383 million under its $1 billion acquisition credit facility dated May 7, 2007. The LIBOR-based borrowing is bearing interest at 3.74 percent as of September 30, 2008. The loan matures in February 2009.

Black Hills Colorado

In conjunction with the sale of IPP assets, the $67.5 million project financing debt for our Black Hills Colorado facilities was paid off.

(6) GUARANTEES

During the nine months ended September 30, 2008, the Company had the following changes to its guarantees:

Extinguished the $111.0 million guarantee to Wygen Funding, Limited Partnership on June 20, 2008 when the Wygen I project debt was repaid and the Company assumed direct ownership of the plant;

Extinguished the $30.0 million guarantee in favor of The Bank of Nova Scotia in July 2008 when the Black Hills Colorado project debt was repaid in conjunction with the IPP Transaction;

Extinguished the $12.0 million guarantee in favor of Public Service Company of New Mexico for obligations and damages, if any, due by Valencia under a power purchase agreement in conjunction with the IPP Transaction in July 2008;

Extinguished the $5.0 million guarantee in favor of Nevada Power Company for payments due by Las Vegas II under the Western Systems Power Pool Confirmation Agreement in conjunction with the IPP Transaction in July 2008;

Issued a guarantee for up to $0.4 million to The Industrial Company for payment obligations arising from a construction contract with Black Hills Non-regulated Holdings. It is a continuing guarantee which terminates upon 45 days written notice to the counterpart;

Extended the expiration of a guarantee for up to $7.0 million related to the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $100.0 million of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company to July 31, 2009; and

Issued the following guarantees for payment obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings, Inc. These commodity transactions secure natural gas supply for our gas utilities. Each guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

§ Up to $25.0 million to BP Energy Company and/or BP Canada Energy Marketing Corp.

§ Up to $25.0 million to Public Service Company of Colorado.

§ Up to $10.0 million to Northern Natural Gas Company.

(7) 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 gives effect to 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, 2008	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 19,522		$ 44,412	
Basic earnings	19,522	38,307	44,412	38,145
Dilutive effect of:				
Stock options		42		62
Estimated contingent shares issuable for prior acquisition				132
Others		76		91
Diluted earnings	$ 19,522	38,425	$ 44,412	38,430

Period ended September 30, 2007	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 11,129		$ 57,498	
Basic earnings	11,129	37,643	57,498	36,810
Dilutive effect of:				
Stock options		111		108
Estimated contingent shares issuable for prior acquisition		159		159
Others		165		149
Diluted earnings	$ 11,129	38,078	$ 57,498	37,226

Basic average shares include the weighted-average effect of the issuance of 451,465 common shares on March 21, 2008 and 4,170,891 common shares on February 27, 2007 (see Notes 9 and 14 for discussion of the March 21, 2008 share issuances).

(8) OTHER COMPREHENSIVE INCOME

The following table presents the components of the Company s other comprehensive income

(in thousands):

	Three Months Ended September 30, 2008	2007
Net income	$ 164,911	$ 17,464
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(14,030) and $3,558, respectively)	25,824	(6,749)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(1,539) and $1,296, respectively)	2,761	(2,406)
Unrealized loss on available for sale securities (net of tax of $17)	(32)	
Total comprehensive income	$ 193,464	$ 8,309

	Nine Months Ended September 30, 2008	2007
Net income	$ 203,898	$ 75,016
Other comprehensive income (loss), net of tax:		
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $6,449 and $3,419, respectively)	(11,951)	(6,521)
Reclassification adjustments on cash flow hedges settled and included in net income (net of tax of $(3,952) and $4,012, respectively)	7,071	(7,787)
Unrealized loss on available for sale securities (net of tax of $58)	(157)	
Total comprehensive income	$ 198,861	$ 60,708

Other comprehensive loss from fair value adjustments on derivatives designated as cash flow hedges in the three and nine months ended September 30, 2008 is primarily attributable to fluctuating oil and gas prices affecting the fair value of natural gas and crude oil swaps held in the Oil and Gas segment and a decrease in interest rates affecting the fair value of interest rate swaps on variable rate debt.

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Unrealized Loss on Available-for-Sale Securities	Total
As of September 30, 2008	$ (23,168)	$ (6,115)	$ (122)	$ (140)	$ (29,545)
As of December 31, 2007	$ (18,178)	$ (6,115)	$ (215)	$	$ (24,508)
As of September 30, 2007	$ (6,248)	$ (8,404)	$ (171)	$	$ (14,823)

(9) COMMON STOCK

Other than the following transactions, the Company had no other material changes in its common stock, as reported in Note 9 of the Notes to Consolidated Financial Statements in the Company s 2007 Annual Report on Form 10-K.

Issuance of Unregistered Securities

On March 21, 2008, the Company issued 451,465 common shares as additional consideration associated with the Acquisition Earn-out Litigation previously disclosed in Note 18 of the Company s 2007 Annual Report on Form 10-K. No additional consideration was received in exchange for the earn-out shares (see Note 14).

Equity Compensation Plans

The Company granted 32,371 target performance shares to certain officers and business unit leaders of the Company for the January 1, 2008 through December 31, 2010 performance period. Actual shares are not issued until the end of the Performance Plan period (December 31, 2010). Performance shares are awarded based on the Company s total shareholder return over the designated performance period as measured against a selected peer group and can range from 0 to 175 percent of target. In addition, the Company s 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 percent in the form of cash and 50 percent in the form of common stock. The grant date fair value was $46.00 per share.

The Company issued 32,568 shares of common stock under the 2007 short-term incentive compensation plan during the nine months ended September 30, 2008. Pre-tax compensation cost related to the award was approximately $1.2 million, which was accrued for in 2007.

The Company granted 80,684 restricted common shares during the nine months ended September 30, 2008. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $3.0 million will be recognized over the three-year vesting period.

90,214 stock options were exercised during the nine months ended September 30, 2008, at a weighted-average exercise price of $25.12 per share providing $2.3 million of proceeds to the Company.

Total compensation expense recognized for all equity compensation plans for the three months ended September 30, 2008 and 2007 was $0.3 million and $1.4 million, respectively, and for the nine months ended September 30, 2008 and 2007 was $1.0 million and $4.4 million, respectively.

As of September 30, 2008, total unrecognized compensation expense related to non-vested stock awards was $4.6 million and is expected to be recognized over a weighted-average period of 2.1 years.

(10) EMPLOYEE BENEFIT PLANS

On July 14, 2008, as disclosed in Note 15, the Company completed the Aquila Transaction adding an additional defined benefit pension plan, a non-pension defined benefit post-retirement healthcare plan, and a 401K retirement savings plan to cover the employees of the utilities acquired. Benefits under these plans are determined based on each employee s compensation, years of service, and/or age at retirement.

Amounts recognized in the Condensed Consolidated Balance Sheet upon the acquisition are (in thousands):

-		Defined Benefit Pension Plan	Non-Pension Defined Benefit Postretirement Plan
Unfunded postretirement benefit obligation	Black Hills Energy	$ 16,105	$ 16,948

Defined Benefit Pension Plan

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Service cost	$ 1,547	$ 687	$ 3,055	$ 2,061
Interest cost	3,165	1,129	5,625	3,387
Expected return on plan assets	(3,644)	(1,374)	(6,790)	(4,122)
Prior service cost	41	38	123	114
Net loss		127		381

Net periodic benefit cost	$ 1,109	$ 607	$ 2,013	$ 1,821

The Company made a $0.5 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2008; no additional contributions are anticipated to be made to the Plans during the 2008 fiscal year. Total contributions to the Plans for 2009 are expected to be approximately $14.5 million.

Supplemental Non-qualified Defined Benefit Plans

The Company has various supplemental retirement plans for key executives of the Company (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,	
	2008	2007	2008	2007
Service cost	$ 112	$ 103	$ 336	$ 309
Interest cost	311	289	933	867
Prior service cost	3	3	9	9
Net loss	142	178	426	534
Net periodic benefit cost	$ 568	$ 573	$ 1,704	$ 1,719

The Company anticipates that it will make contributions to the Supplemental Plans for the 2008 fiscal year of approximately $0.8 million. The contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Healthcare Plans

Employees who are participants in the Company s Postretirement Healthcare Plans (Healthcare Plans) and who meet certain eligibility requirements are entitled to postretirement healthcare benefits.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Service cost	$ 226	$ 135	$ 476	$ 405

Interest cost	503	207	937	621
Expected return on Plan assets	(43)		(43)	
Net transition obligation	15	15	45	45
Net gain	(20)	(4)	(60)	(12)
Net periodic benefit cost	$ 681	$ 353	$ 1,355	$ 1,059

The Company anticipates that it will make contributions to the Healthcare Plans for the 2008 fiscal year of approximately $0.3 million. The contributions are expected to be made in the form of benefits payments.

It has been determined that the Company s 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 $0.2 million for each of the three and nine month periods ended September 30, 2008 and 2007.

(11) SUMMARY OF INFORMATION RELATING TO SEGMENTS OF THE COMPANY S BUSINESS

The Company s reportable segments are those that are based on the Company s method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of September 30, 2008, substantially all of the Company s operations and assets are located within the United States.

Prior to the third quarter of 2008, we managed our business in six reporting segments within two business groups: Utilities and Non-regulated Energy. Utilities consisted of two reporting segments, including the Electric Utility segment (Black Hills Power) and the combination Electric and Gas Utility segment (Cheyenne Light). Non-regulated Energy consisted of four reporting segments, including our Coal Mining, Energy Marketing, Power Generation, and Oil and Gas segments.

In the third quarter of 2008, we changed the reporting segments within our Utilities Group to reflect the significant change to our utility business resulting from the Aquila Transaction (see Note 15). Effective for the period ending September 30, 2008, the Utilities Group includes two reporting 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 includes 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, provide stable gross margins and overall financial results. Periodic variances are therefore rarely expected to significantly impact the operating results discussions 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 consists of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas.

On July 11, 2008, the Company sold entities that owned seven of its IPP assets with a total capacity of 974 megawatts. The financial information related to these plants was previously reported in the Power Generation segment and has been reclassified to discontinued operations. The Company s remaining IPP assets will continue to be reported in the Power Generation segment.

The Company now conducts its operations through the following six reporting segments:

Utilities Group

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

Gas Utilities, which supply natural gas utility service in Colorado, Iowa, Nebraska and Kansas.

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. Subsequent to the July 11, 2008 sale of seven IPP plants, the remaining segment assets include power plant assets located in Wyoming, California and Idaho;

Coal Mining, which engages in the mining and sale of coal from its 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 20 of the Notes to Consolidated Financial Statements in the Company s 2007 Annual Report on Form 10-K. In accordance with the provisions of SFAS 71, intercompany fuel sales to the regulated utilities are not eliminated.

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

Three Month Period Ended September 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 136,644	$ 334	$ 10,765
Gas Utilities	83,937		(1,854)
Non-regulated Energy:			
Oil and Gas	25,438		1,517
Power Generation	11,704		3,197
Coal Mining	8,103	7,928	1,092
Energy Marketing	19,196		6,902
Corporate			(2,061)
Inter-segment eliminations		(1,392)	(36)
Total	$ 285,022	$ 6,870	$ 19,522

Three Month Period Ended September 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 72,275	$ 645	$ 7,189
Non-regulated Energy:			
Oil and Gas	24,291		1,979
Power Generation	10,048		(900)
Coal Mining	6,818	3,628	1,358
Energy Marketing	13,873		2,290
Corporate			(787)
Inter-segment eliminations		(1,411)	
Total	$ 127,305	$ 2,862	$ 11,129

Nine Month Period Ended September 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 329,512	$ 1,004	$ 30,485
Gas Utilities	83,937		(1,854)
Non-regulated Energy:			
Oil and Gas	85,770		11,266
Power Generation	29,079		1,698
Coal Mining	23,979	17,946	3,217
Energy Marketing	30,465		7,565
Corporate			(7,889)
Inter-segment eliminations		(3,677)	(76)
Total	$ 582,742	$ 15,273	$ 44,412

Nine Month Period Ended September 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric Utilities	$ 222,033	$ 1,641	$ 22,884
Non-regulated Energy:			
Oil and Gas	75,948		9,945
Power Generation	30,123		(1,850)
Coal Mining	19,458	10,734	4,353
Energy Marketing	65,220		23,886
Corporate			(1,720)
Inter-segment eliminations		(3,967)	
Total	$ 412,782	$ 8,408	$ 57,498

During 2008, the Company's assets increased approximately $0.8 billion. The assets increased as a result of the Aquila Transaction (see Note 15), the ongoing construction of the Wygen III power plant within the Electric Utilities segment, and other additions of maintenance and deployment capital (see Capital Requirements on page 67) offset by the IPP Transactions (see Note 16).

(12) RISK MANAGEMENT ACTIVITIES

The Company actively manages its exposure to certain market risks as described in Note 2 of the Notes to Consolidated Financial Statements in the Company s 2007 Annual Report on Form

10-K. Details of derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income are as follows:

Trading Activities

Natural Gas and Crude Oil Marketing

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

	Outstanding at September 30, 2008		Outstanding at December 31, 2007		Outstanding at September 30, 2007	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)						
Natural gas basis swaps purchased	184,099	37	125,577	36	150,499	27
Natural gas basis swaps sold	180,322	37	128,892	36	158,349	27
Natural gas fixed for float swaps purchased	73,872	24	42,326	24	51,958	25
Natural gas fixed for float swaps sold	84,786	24	59,253	24	70,379	25
Natural gas physical purchases	146,273	18	90,583	15	95,028	18
Natural gas physical sales	182,512	24	98,888	27	93,008	30
Natural gas options purchased	3,958	6	3,472	10	31,973	6
Natural gas options sold	3,958	6	3,472	10	31,539	6

	Outstanding at September 30, 2008		Outstanding at December 31, 2007		Outstanding at September 30, 2007	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of Bbls)						
Crude oil physical purchases	5,994	15	4,991	12	1,619	7
Crude oil physical sales	4,690	15	3,800	12	1,370	5
Crude oil swaps/options purchased	465	24	495	12	465	12
Crude oil swaps/options sold	525	24	495	12	465	12
(Dollars, in thousands)						
Canadian dollars purchased	$ 25,000	1	$ 28,000	2	$ 29,000	1
Canadian dollars sold	$ 3,000	1	$		$	

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on September 30, 2008, December 31, 2007 and September 30, 2007, 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):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Cash Collateral Included in Derivative Assets/ Liabilities	Unrealized (Loss) Gain
September 30, 2008	$ 66,807	$ (1,140)	$ 22,292	$ (227)	$ 1,789	$ 45,391
December 31, 2007	$ 30,999	$ 1,901	$ 16,908	$ 2,482	$ 1,287	$ 14,797
September 30, 2007	$ 24,694	$ 522	$ 12,154	$ 619	$ (2,511)	$ 9,932

FSP FIN 39-1 permits a reporting entity to offset 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 arrangement. Each Condensed Consolidated Balance Sheet herein reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when management believes a legal right of offset exists. Accordingly, December 31, 2007 and September 30, 2007 amounts have been reclassified to conform to this presentation.

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 inventory on the 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, 2008, December 31, 2007 and September 30, 2007, the market adjustments recorded in inventory were $(15.1) million, $(9.8) million and $(6.5) million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

On September 30, 2008, December 31, 2007 and September 30, 2007, the Company had the following derivatives and related balances (in thousands):

	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
September 30, 2008								
Crude oil swaps/options	465,000	0.25	$ 1,309	$ 909	$ 3,955	$ 1,268	$ (4,308)	$ 1,303
Natural gas swaps	9,231,000	1.08	7,391	1,632	236	165	8,622	
			$ 8,700	$ 2,541	$ 4,191	$ 1,433	$ 4,314	$ 1,303
December 31, 2007								
Crude oil swaps/options	495,000	1.00	$ 352	$	$ 3,506	$ 1,794	$ (5,300)	$ 352
Natural gas swaps	11,406,000	1.59	4,332	591	507	825	3,587	4
			$ 4,684	$ 591	$ 4,013	$ 2,619	$ (1,713)	$ 356
September 30, 2007								
Crude oil swaps/options	465,000	1.00	$ 490	$	$ 1,995	$ 688	$ (2,683)	$ 490
Natural gas swaps	11,180,500	1.60	6,712	872	494	1,035	6,403	(348)
			$ 7,202	$ 872	$ 2,489	$ 1,723	$ 3,720	$ 142

*crude in Bbls, gas in MMBtus

Based on September 30, 2008 market prices, a $1.9 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.

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Regulated Gas Utilities

The contract or notional amounts and terms of the Company s natural gas derivative commodity instruments are as follows:

	Outstanding at September 30, 2008 Notional Amounts	Latest Expiration (months)
(in thousands of MMBtus)		
Natural gas futures purchases	2,730	6
Natural gas futures sales		
Natural gas options purchased	8,760	6
Natural gas options sold	1,800	6

On September 30, 2008, the Company had the following derivatives and related balances (in thousands):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Regulatory Assets	Cash Collateral Included in Derivative Assets/ Liabilities
September 30, 2008	$ 9,424	$	$ 5,241	$	$ 17,991	$ 12,751

*gas in MMBtus

Our Gas Utilities segment purchases and distributes natural gas in four states. All of our gas utilities have Purchased Gas Adjustment (PGA) provisions that allow them to pass the cost of gas to the consumer. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. These adjustments are subject to periodic prudence reviews by the respective state utility commissions. In addition, as allowed or required by state utility commissions, we have entered into certain exchange traded natural gas futures and option transactions to reduce our customers underlying exposure to fluctuations in gas prices. These transactions are considered derivative transactions under SFAS 133 and are marked-to-market and recorded as derivative assets or liabilities on the accompanying Condensed Consolidated Balance Sheet.

Financing Activities

On September 30, 2008, December 31, 2007 and September 30, 2007, the Company s interest rate swaps and related balances were as follows (in thousands):

	Current Notional Amount	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive (Loss)/Income
September 30, 2008								
Interest rate swaps	$ 150,000	5.04%	8.00	$	$	$ 2,588	$ 5,586	$ (8,174)
December 31, 2007								
Interest rate swaps	$ 150,000	5.04%	8.75	$	$	$ 1,792	$ 4,274	$ (6,066)
September 30, 2007								
Interest rate swaps	$ 150,000	5.04%	9.00	$	$ 1,352	$ 666	$ 599	$ 87

Based on September 30, 2008 market interest rates and balances, a loss of approximately $2.6 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

In addition to the interest rate swaps above, during the third quarter of 2007, the Company entered into forward starting interest rate swaps with a total notional amount of $250.0 million to hedge the risk of interest rate movement between the hedge dates and the expected pricing date for a portion of the Company s anticipated 2008 long-term debt financings. The swaps have an amended mandatory early termination date of December 15, 2008. As of September 30, 2008, the mark-to-market value was $(28.1) million. These swaps have been designated as cash flow hedges and accordingly, any resulting gain or loss will be recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheet and amortized into earnings as additional interest income or expense over the life of the related long-term financing. Refer to Note 19 for further information regarding these swaps subsequent to September 30, 2008.

(13) FAIR VALUE MEASUREMENTS

Adoption of SFAS 157

Effective January 1, 2008, the Company adopted SFAS 157 as discussed in Note 2, which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value.

SFAS 157 provides a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As permitted under SFAS 157, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing a significant portion of its assets and liabilities measured and reported at fair value. SFAS 157 also requires enhanced disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The Company is able to classify fair value balances based on the observability of inputs.

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 table sets forth by level within the fair value hierarchy the Company s assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels.

Recurring Fair Value Measures (in thousands)	At Fair Value as of September 30, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting (a)	Total
Assets:					
Short-term investments	$	$	$ 6,310	$	$ 6,310
Commodity derivatives	9,424	252,032	19,368	(194,989)	85,835
Foreign currency derivatives		423			423
Regulatory asset	17,991				17,991
Total	$ 27,415	$ 252,455	$ 25,678	$ (194,989)	$ 110,559
Liabilities:					
Commodity derivatives	$ 7,030	$ 207,840	$ 13,048	$ (194,989)	$ 32,929
Interest rate swaps		36,272			36,272
Total	$ 7,030	$ 244,112	$ 13,048	$ (194,989)	$ 69,201

(a) FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between the Company and a contractual counterparty.

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

	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 losses 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 Condensed Consolidated Statement of Income. The Company believes 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 income on the Condensed Consolidated Balance Sheet.

(14) COMMITMENTS AND CONTINGENCIES

Acquired Utilities

In connection with the Aquila Transaction (see Note 15), the Company assumed various commitments relating to power, natural gas and coal supply commitments and lease commitments, as summarized below.

In millions	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**
Future minimum payments							
Facilities and equipment	$ 4.5	$ 3.5	$ 2.4	$ 1.8	$ 1.0	$ 1.2	$ 14.4
Regulated business purchase obligations:							
Purchased power obligations [1]	35.7	37.0	38.3	39.7			150.7
Pipeline capacity obligations	53.7	52.0	52.1	49.4	42.8	68.1	318.1
Coal and rail contracts	8.3						8.3

(1) Represents demand charges for capacity under Colorado Electric power purchase agreements.

In 2007, Colorado Electric purchased 89 percent of the power delivered to its customers. The majority of this power was purchased under a long-term contract with a term through 2011, which provides for capacity of 270 MW in 2008 increasing 10 MW per year to 300 MW in 2011. Colorado Electric also purchases coal and natural gas, including transportation capacity, as fuel for its generating power plants under short-term and long-term contracts through 2008. The Gas Utility operations purchase natural gas, including fixed commitments for pipeline transportation capacity, to meet customer needs under short- and long-term contracts with varying terms through 2028.

LEGAL PROCEEDINGS

The Company is subject to various legal proceedings, claims and litigation as described in Note 18 of the Notes to Consolidated Financial Statements in the Company s 2007 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 2008.

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, 2008, cannot be reasonably determined and could have a material adverse effect on our results of operations or financial position.

Earn-Out Litigation

We are defending two proceedings brought by former stockholders of Indeck, a company we acquired in 2000. The first proceeding, a civil lawsuit, is pending in federal court in Illinois. The second proceeding is an arbitration proceeding brought under the terms of a merger agreement that provided for contingent payment of earn-out consideration to the former Indeck stockholders. On March 21, 2008, the parties settled the lawsuit. Under the settlement agreement, we agreed to pay additional earn-out consideration to the former Indeck stockholders. The aggregate value of the 451,465 shares of additional Black Hills common stock issued was recorded as additional goodwill. The merger agreement provided a $35.0 million cap or maximum amount of earn-out consideration payable with respect to the earn-out provision. With the payment made in settlement of the litigation to date, we have paid in common stock an aggregate value of $23.5 million.

The trial court entered an order approving the settlement agreement on March 27, 2008. The order provides all lawsuit claims are dismissed without prejudice pending completion of the arbitration. The court retains jurisdiction over the parties for the purpose of enforcing the order entered in the pending arbitration. Once the parties submit a final order to the court upon completion of the arbitration, the dismissal of all claims will convert to a dismissal with prejudice.

On September 19, 2008, the arbitrator issued its order in the Company s favor, holding that no earn-out consideration was due by reason of the impairment of the Las Vegas II facility, and its related impact upon the 2003 earn-out payment. The arbitrator, however, instructed the Company to pay approximately $4.0 million in earn-out consideration that the Company tendered for payment for the 2003 earn-out period. We believe this reference was in error on the grounds that the amount offered for the 2003 earn-out period was included in the litigation settlements and therefore, has already been paid. We filed with the U.S. District Court our Motion to Modify the Arbitration Award, to delete this directive. The Indeck stockholders oppose this request. A hearing date is set for December 4, 2008, at which time we expect the court to issue a final decision. We believe that the court will accept our position, and deem the entire dispute now to be concluded. If any additional consideration is awarded, however, it would be recorded as additional goodwill, which would be subject to a recoverability analysis under GAAP. An award of interest, if any, would be recorded as a charge to earnings.

Las Vegas Cogeneration/Nevada Power Company Arbitration

Our wholly-owned subsidiary, LVC, was involved in an arbitration proceeding with Nevada Power concerning the power purchase agreement at our Las Vegas I facility. The parties reached a settlement in early December 2007, and the settlement agreement was approved by the PUCN on April 4, 2008. As a result of this settlement, the status of LVC as a qualifying facility under federal law was terminated, as were its contracts with Nevada Power. LVC was included in the Company s sale of IPP assets (see Note 16).

(15) ACQUISITION

Aquila Transaction

On February 7, 2007, the Company entered into a definitive agreement with Aquila for the asset acquisition of Aquila s regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa for $940 million, subject to customary closing adjustments. Based on working capital, capital expenditure and other adjustments, we paid $908.8 million in cash to Aquila and completed the acquisition on July 14, 2008. Additionally, approximately $28.8 million of fees and other costs were capitalized as part of the purchase price. We expect to finalize the purchase price adjustments and allocations in the first half of 2009. The purchase price was financed through a $383 million borrowing on the Company s $1 billion acquisition credit facility and from cash proceeds generated from the Company s IPP Transaction.

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. The estimated purchase price allocations are subject to adjustment, generally within one year of the date of acquisition. Allocation of the purchase price is as follows (in thousands):

Current assets	$	113,798
Property, plant and equipment		547,144
Derivative assets		4,695
Goodwill		386,959
Deferred assets		25,029
	$	1,077,625
Current liabilities	$	92,446
Deferred credits and other liabilities		47,570
	$	140,016
Net assets	$	937,609

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 and 2007, respectively (in thousands):

	Three Month Period Ended		Nine Month Period Ended	
	September 30, 2008	September 30, 2007	September 30, 2008	September 30, 2007
Operating revenues	$ 314,090	$ 253,537	$ 1,140,913	$ 1,011,951
Income from continuing operations	19,890	11,724	68,809	76,819
Net income	165,279	18,059	228,295	94,337
Earnings per share				
Basic:				
Continuing operations	$ 0.52	$ 0.31	$ 1.80	$ 2.09
Total	$ 4.32	$ 0.48	$ 5.99	$ 2.56
Diluted:				
Continuing operations	$ 0.52	$ 0.31	$ 1.79	$ 2.06
Total	$ 4.30	$ 0.47	$ 5.94	$ 2.53

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.

(16) DISCONTINUED OPERATIONS

The Company accounts for its discontinued operations under the provisions of SFAS 144. Accordingly, 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, the Company entered into a definitive agreement to sell seven of its 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, the Company 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 by the Company. The after-tax gain recorded on the asset sale was approximately $141.7 million. For business segment reporting purposes, results were previously included in the Power Generation segment.

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

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008*	Nine Months Ended September 30, 2007
Operating revenues	$ 5,507	$ 32,187	$ 59,572	$ 91,640
Pre-tax income from discontinued operations	5,288	10,630	27,141	28,086
Gain on sale	235,671		235,671	
Income tax expense	95,849	4,117	103,803	10,210
Net income from discontinued operations	$ 145,110	$ 6,513	$ 159,009	$ 17,876

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

Allocation of corporate expenses to discontinued operations was made in accordance with SFAS 144 and EITF 87-24. The indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations were $0 and $3.2 million for the three months ended September 30, 2008 and 2007, respectively and $7.7 million and $9.1 million for the nine months ended September 30, 2008 and 2007, respectively. These allocated costs remain in the Power Generation segment.

Interest expenses included within the operations of the discontinued entities was recorded pursuant to EITF 87-24 and includes interest expense on debt which was required to be repaid as a result of the sale transaction. In accordance with EITF 87-24, 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 months ended September 30, 2008 and 2007, interest expense allocated to discontinued operations was $0 and $2.5 million, respectively. For the nine months ended September 30, 2008 and 2007, the interest expense allocated to discontinued operations was $4.7 million and $8.5 million, respectively.

Net assets associated with the divested IPP plants were as follows (in thousands):

	December 31, 2007	September 30, 2007
Current assets	$ 34,112	$ 31,579
Property, plant and equipment, net of accumulated depreciation	486,156	478,521
Goodwill	18,095	18,095
Intangible assets (net of accumulated amortization of $28,114 and $27,363, respectively)	21,023	21,774
Other non-current assets	13,163	12,431
Current liabilities	(15,615)	(12,768)
Note payable		(29,148)
Long-tem debt	(73,928)	(77,143)
Other non-current liabilities	(139)	(247)
Net assets	$ 482,867	$ 443,094

(17) IMPAIRMENT OF LONG-LIVED ASSETS

During September 2007, the Company assessed the recoverability of the carrying value of the Ontario power plant due to a thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. In addition, $1.4 million was accrued for contract termination and decommissioning costs. These charges are included as a component of Operating expenses on the accompanying Condensed Consolidated Statement of Income. Operating results from the Ontario plant are included in the Power Generation segment.

(18) VARIABLE INTEREST ENTITY

The Company s subsidiary, Black Hills Wyoming, had an Agreement for Lease and Lease with Wygen Funding, Limited Partnership, an unrelated VIE, to lease the Wygen Plant. The Company was considered the primary beneficiary and included the VIE in the Company s consolidated financial statements. At the end of the initial lease term in June 2008, the Company elected to purchase the Wygen Plant at the adjusted acquisition cost of $133.1 million. In conjunction with the purchase of the Wygen Plant, the Company retired the $128.3 million Wygen I project debt through borrowings on the Company s revolving credit facility, and extinguished the $111 million guarantee obligation under the Wygen I Plant Lease. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

(19) SUBSEQUENT EVENTS

Interest Rate Swaps

As described under Financing Activities within Note 12, the Company has forward starting interest rate swaps with a notional amount of $250.0 million. These swaps were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were designated as cash flow hedges in accordance with SFAS 133 and at September 30, 2008, they had a mark-to-market value of $(28.1) million, which was recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheet.

Subsequent to September 30, 2008, based on credit market conditions that transpired in October, the Company determined that the forecasted long-term debt financings described in Note 12 were no longer probable of occurring in the time period specified. The Company continues to evaluate its near term financing alternatives, which may include long-term financings and/or the use of other financing alternatives with a shorter duration. As a result of the originally forecasted long-term financings no longer being probable of occurring within the originally specified time period, the swaps were no longer effective hedges in accordance with SFAS 133 and the hedge relationships were de-designated. On the date of de-designation, the swaps had a mark-to-market value of approximately $(42.7) million. This value will remain in Accumulated other comprehensive loss and subsequent mark-to-market adjustments to the swaps will be recorded within the income statement. Should the Company complete a long-term financing with terms that are closely correlated to the hedged forecasted transactions, then the amount in Accumulated other comprehensive loss will be amortized and recorded as interest expense over the term of the underlying debt. If the Company determines that the long-term financing is probable of not occurring by the end of the originally specified time period, the balance in Accumulated other comprehensive loss related to the swaps will be immediately recorded as a charge to earnings.

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 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 198,000 customers in South Dakota, Wyoming, Colorado and Montana. In addition, Cheyenne Light provides natural gas to customers in Wyoming, which is also reported within the Electric Utilities segment. Our Gas Utilities segment serves approximately 550,000 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 Beginning on Page 69.

Operating Strategy

In the third quarter of 2008, we completed two transactions (the IPP Transaction and the Aquila Transaction) that transformed our Company from a largely unregulated energy company into an energy company with substantial regulated and unregulated operations. As a result of these transactions, as of September 30, 2008, our utility properties represented 66 percent of our consolidated assets and generated roughly 46 percent of our earnings during the quarter. These transactions improved our liquidity, credit and financial profiles, and provide us a platform for executing on our long-term strategic plan for increasing shareholder value.

Within our Utilities Group, we are focused on (i) integrating the Aquila Transaction properties into our businesses, systems and processes, (ii) improving returns through rate activities and process improvements, (iii) building and maintaining the generation and transmission infrastructure necessary to provide cost-effective, safe and reliable service, and (iv) balancing the desire (and, as applicable, requirement) for alternative and renewable energy with customer rate impacts.

Within our Non-regulated Energy Group, we are focused on selectively growing our Power Generation business and optimizing capacity and energy sales by entering into long-term contracts with utilities, and expanding our mine-mouth coal production levels and increasing third-party coal sales. We are also focused on growing our Oil and Gas business through the development of existing properties and through opportunistic acquisitions of oil and gas properties, and managing the marketing risks of our energy marketing business while expanding its geographic footprint.

In addition, we are focused on refinancing existing debt (including debt incurred to fund the Aquila Transaction) and raising the capital needed to fund anticipated capital expenditures. See Future Financing Plans on Page 67.

Significant Events

<u>Sale of IPP Plants</u>

On April 29, 2008, the Company entered into a definitive agreement to sell seven of its 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, the Company received net pre-tax cash proceeds of approximately $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 by the Company. Additionally, we expect to make income tax payments associated with the gain on the asset sale of approximately $50 million to $75 million. Through tax planning, we expect to defer tax payments in the range of $135 million to $160 million. The pre-tax book gain on the asset sale is $235.7 million. For business segment reporting purposes, results were previously included in the Power Generation segment.

The following power plants were included in the sale to Hastings and IIF:

Asset (State)	Capacity (net megawatts)
Fountain Valley (Colorado)	240
Las Vegas II (Nevada)	224
Valencia (New Mexico)	149
Arapahoe (Colorado)	130
Harbor Cogeneration (California)	98
Valmont (Colorado)	80
Las Vegas I (Nevada)	53
Total	974

The following power plant assets remain with the Company in the Power Generation business segment of our Non-regulated Energy Group:

Asset (State)	Capacity (net megawatts)
Wygen I (Wyoming)*	90
Gillette CT (Wyoming)	40
Ontario Cogeneration (California)	12
Rupert and Glenns Ferry Cogeneration (Idaho)**	11
Power fund investments (various locations)	5
Total	158

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* Mine-mouth coal-fired base load generation
** Capacity represents the Company s 50 percent interest in the two power plants
See Note 16 to our condensed consolidated financial statements.

Wygen III Power Plant Project

In March 2008, we received final regulatory approval for construction of Wygen III. Construction began immediately and the 100 MW coal-fired base load electric generating facility is expected to take 24 to 30 months to complete. The expected cost of construction is approximately $255 million, which includes estimates for AFUDC. Through Black Hills Power we expect to retain ownership of 75 MW of the facility s capacity with MDU currently being expected to take ownership of the remaining 25 MW. We will retain responsibility for operations of the facility with a life-of-plant site lease, and operations and coal supply agreements in place with MDU.

Air-cooled Condenser Upgrade Project

We recently commenced a project to expand the air-cooled condensers on our Wygen I and Neil Simpson II coal-fired plants. The upgrades will cost approximately $8.0 million per plant and will add approximately 8.2 megawatts of rated capacity to each plant. This represents additional base load installed capacity at approximately $995 per kilowatt. The project is expected to be completed in 2009.

Partial Sale of Wygen I to MEAN

During August 2008, we entered into a definitive agreement to sell a 23.5 percent ownership interest in the Wygen I plant to MEAN. The sales price is based on current replacement cost for the coal-fired plant, so we expect to realize a significant gain on the completed sale. We will retain responsibility for operations of the plant and at closing will enter into a site lease, and coal supply and operating agreements with MEAN. We currently expect that all conditions to closing will be satisfied and that closing will occur prior to the end of 2008.

We currently have a long-term contract to sell 20 MW of capacity and energy from the Wygen I plant to MEAN, which expires in 2013. This contract will be terminated upon the closing of the sale.

Acquisition of Aquila Utility Assets

On February 7, 2007, we entered into a definitive agreement with Aquila for the acquisition of Aquila s regulated electric utility assets in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa for $940 million, subject to customary closing adjustments. On July 14, 2008, the acquisition was completed. The purchase price was financed through a $383 million borrowing on the Company s $1 billion acquisition credit facility and from cash proceeds generated from the Company s IPP asset sale, which was completed on July 11, 2008.

Results of Operations

Executive Summary

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007.

Income from continuing operations for the three month period ended September 30, 2008 was $19.5 million, or $0.51 per share, compared to $11.1 million, or $0.29 per share, reported for the same period in 2007. Results for the three months ended September 30, 2008 increased over the same period of the prior year primarily due to higher earnings from the Non-regulated Energy Group. For the three month period ended September 30, 2008, net income was $164.9 million or $4.29 per share, compared to $17.5 million, or $0.46 per share, for the same period in 2007. The increased net income includes a $141.7 million, or $3.69 per share, after-tax gain from the sale of the IPP assets on July 11, 2008, and is classified as discontinued operations.

The Utility group includes the results from the acquisition date of the electric and gas utilities acquired from Aquila on July 14, 2008. Utilities earnings also benefited from a 2008 rate increase for Cheyenne Light partially offset by increased costs primarily related to Wygen II plant operations and depreciation and lower AFUDC. The Wygen II plant began commercial operation on January 1, 2008. Black Hills Power earnings reflect the impact of AFUDC related to the Wygen III construction partially offset by lower margins on retail and wholesale sales. Fuel and purchased power cost increases were a result of increased coal costs and increased usage of higher cost gas-fired generation facilities.

Earnings from the Oil and Gas segment decreased for the quarter due to lower production, lower gas prices and an increase in operating expenses caused by higher fuel costs and increased production taxes offset by an increase in revenues due to higher average prices received for oil. Third quarter 2008 production was 11 percent lower than third quarter 2007 primarily due to delays caused by weather-related impacts at the beginning of 2008 and lower production from non-operated properties. Average hedged oil prices increased 34 percent and average hedged gas prices decreased 2 percent.

Earnings from the Power Generation segment reflect the sale of the IPP assets and reclassification to discontinued operations. Continuing operations for this segment include Wygen I, the Gillette CT, Ontario, Rupert and Glenns Ferry and power fund investments. Indirect corporate costs and inter-segment net interest expense not reclassified to discontinued operations were $3.2 million after-tax for the three months ended September 30, 2007. These costs were historically allocated to the Power Generation segment, but will be reallocated in future periods to reflect the recent changes in our business and asset mix.

Lower earnings from the Coal Mining segment resulted from increased overburden removal costs, depreciation, fuel costs and coal taxes, partially offset by revenue increases from higher production and higher average sale price.

Earnings from the Energy Marketing segment reflect higher unrealized mark-to-market gains partially offset by lower realized natural gas margins and crude oil margins received. Realized natural gas margins were impacted by changes in market conditions as lower geographic and calendar spreads compared to 2007 contributed to the earnings decline. Lower operating expenses reflect lower incentive compensation related to the decrease in realized natural gas margins and lower administrative expenses.

Earnings from discontinued operations were $145.4 million, or $3.78 per share, for the three month period ended September 30, 2008, compared to $6.3 million, or $0.17 per share, for the same period in 2007. The increased earnings include a $141.7 million, or $3.69 per share, after-tax gain from the sale of the IPP assets on July 11, 2008. In addition, earnings from discontinued operations primarily reflect that during the second quarter of 2008 we ceased depreciation and amortization on the IPP assets to be sold.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007.

Income from continuing operations for the nine month period ended September 30, 2008 was $44.4 million, or $1.16 per share, compared to $57.5 million, or $1.55 per share, reported for the same period in 2007. Results for the nine months ended September 30, 2008 decreased from the same period of the prior year primarily due to lower earnings from the Non-regulated Energy Group. For the nine month period ended September 30, 2008, net income was $203.9 million or $5.31 per share, compared to $75.0 million, or $2.02 per share, for the same period in 2007. The increased net income includes a $141.7 million, or $3.69 per share, after-tax gain from the sale of the IPP assets on July 11, 2008, and is classified as discontinued operations.

The Utilities Group includes results from the acquisition date of the electric and gas utilities acquired from Aquila on July 14, 2008. Utilities earnings also benefited from a 2008 rate increase at Cheyenne Light and higher electric usage, partially offset by increased costs primarily related to Wygen II plant operations and depreciation and lower AFUDC. Black Hills Power earnings increased due to higher margins from off-system sales and the impact of AFUDC related to the Wygen III construction partially offset by lower margins on retail and wholesale sales. Fuel and purchased power cost increases reflect additional power purchased to meet native load during scheduled and unscheduled plant outages.

Earnings from the Oil and Gas segment increased for the nine month period driven by higher revenues due to higher average prices received for oil and gas, offset by lower production. Revenues for the period were also negatively impacted by a $2.1 million pre-tax accrual for a royalty settlement with the Jicarilla Apache Nation. Higher LOE and increased production taxes due to the increase in prices partially offset the increased revenues. Year to date 2008 production was 8 percent lower than the same period in 2007 primarily due to delays caused by weather-related impacts at the beginning of 2008 and lower production from non-operated properties. Average hedged oil prices increased 50 percent and average hedged gas prices increased 11 percent.

Earnings from the Power Generation segment reflect the sale of the IPP assets and reclassification to discontinued operations. Continuing operations for this segment include Wygen I, the Gillette CT, Ontario, Rupert and Glenns Ferry power plants and power fund investments. Indirect corporate costs and inter-segment net interest expense not reclassified to discontinued operations were $7.7 million and $9.1 million after-tax for the nine month periods ended September 30, 2008 and 2007, respectively. These costs were historically allocated to the Power Generation segment, but will be reallocated in future periods to reflect the recent changes in our business and asset mix.

A decrease in earnings from the Coal Mining segment resulted from increased fuel costs, coal taxes, depreciation and overburden removal costs, partially offset by revenue increases from higher production and higher average sales price.

Earnings from the Energy Marketing segment reflect lower realized natural gas margins received partially offset by increased unrealized mark-to-market gains. Realized natural gas margins were impacted by changes in market conditions as lower geographic and calendar spreads contributed to the earnings decline. Lower operating expenses reflect lower incentive compensation related to the decrease in realized natural gas margins and lower administrative expenses.

Earnings from discontinued operations were $159.5 million, or $4.15 per share, for the nine month period ended September 30, 2008, compared to $17.5 million, or $0.47 per share, for the same period in 2007. The increased earnings include a $141.7 million, or $3.69 per share, after-tax gain from the sale of the IPP assets on July 11, 2008. In addition, earnings from discontinued operations primarily reflect that during the second quarter of 2008 we ceased depreciation and amortization on the IPP assets to be sold.

Consolidated Results

Revenues and Income (Loss) from Continuing Operations provided by each business group were as follows (in thousands):

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Revenues				
Utilities	$ 220,581	$ 72,275	$ 413,449	$ 222,033
Non-regulated Energy	71,311	57,892	184,566	199,157
	$ 291,892	$ 130,167	$ 598,015	$ 421,190
Income (loss) from continuing operations				
Utilities	$ 8,911	$ 7,189	$ 28,631	$ 22,884
Non-regulated Energy	12,672	4,727	23,670	36,334
Corporate	(2,061)	(787)	(7,889)	(1,720)
	$ 19,522	$ 11,129	$ 44,412	$ 57,498

Income from continuing operations increased $8.4 million for the three months ended September 30, 2008 due primarily to the following:

- a $3.6 million increase in Electric Utilities earnings;
- a $4.1 million increase in Power Generation earnings; and
- a $4.6 million increase in Energy Marketing earnings.

The increases in earnings were partially offset by:

- a $1.9 million loss from the Gas Utilities segment;
- a $0.5 million decrease in Oil and Gas earnings;
- a $0.3 million decrease in Coal Mining earnings; and
- a $1.3 million increase in unallocated corporate costs.

Income from continuing operations decreased $13.1 million for the nine months ended September 30, 2008 due primarily to the following:

- a $16.3 million decrease in Energy Marketing earnings;
- a $1.1 million decrease in Coal Mining earnings;
- a $1.9 million loss from the Gas Utilities segment; and
- a $6.2 million increase in unallocated corporate costs.

These results were partially offset by:

- a $7.6 million increase from Electric Utilities earnings;
- a $1.3 million increase in Oil and Gas earnings; and
- a $3.5 million increase in Power Generation 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.

The following business group and segment information does not include intercompany eliminations or results of discontinued operations.

Utilities Group

We acquired from Aquila their regulated electric utility assets in Colorado and gas utilities assets 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 natural gas operations within our combination utility, Cheyenne Light, provide stable gross margins and overall financial results. Periodic variances are therefore rarely expected to significantly impact the operating results discussions for the Electric Utilities segment. 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,	
	2008	2007	2008	2007
	(in thousands)			
Revenue electric	$ 131,193	$ 70,266	$ 295,946	$ 198,062
Revenue gas	5,785	2,654	34,570	25,612
Total revenue	136,978	72,920	330,516	223,674
Fuel and purchased power electric	74,162	36,275	152,364	96,571
Purchased gas	3,596	1,077	24,051	18,555
Total fuel and purchased power	77,758	37,352	176,415	115,126
Gross margin electric	57,031	33,991	143,582	101,491
Gross margin gas	2,189	1,577	10,519	7,057
Total gross margin	59,220	35,568	154,101	108,548
Operating expenses	38,561	23,003	95,654	69,872
Operating income	$ 20,659	$ 12,565	$ 58,447	$ 38,676
Income from continuing operations and net income	$ 10,765	$ 7,189	$ 30,485	$ 22,884

The following tables provide certain operating statistics for the Electric Utilities segment:

Electric Revenue
(in thousands)

Customer Base	Three Months Ended September 30, 2008	Percentage Change	2007	Nine Months Ended September 30, 2008	Percentage Change	2007
Commercial	$ 43,894	65%	$ 26,675	$ 93,779	31%	$ 71,703
Residential	34,969	88	18,597	74,386	41	52,798
Industrial	16,085	117	7,404	31,090	44	21,604
Municipal sales	2,221	121	1,003	3,957	51	2,627
Total retail sales	97,169	81	53,679	203,212	37	148,732
Contract wholesale	8,358	27	6,566	24,431	30	18,855
Wholesale off system	17,667	147	7,157	55,312	161	21,155
Total electric sales	123,194	83	67,402	282,955	50	188,742
Other revenue	7,999	179	2,864	12,991	39	9,320
Total revenue	$ 131,193	87%	$ 70,266	$ 295,946	49%	$ 198,062

Electric Utilities
Megawatt Hours Sold

Customer Base	Three Months Ended September 30, 2008	Percentage Change	2007	Nine Months Ended September 30, 2008	Percentage Change	2007
Commercial	517,698	46%	353,410	1,140,237	20%	946,461
Residential	322,819	62	199,167	732,626	25	585,294
Industrial	256,670	73	148,239	538,138	26	426,946
Municipal sales	21,750	89	11,486	39,357	38	28,454
Total retail sales	1,118,937	57	712,302	2,450,358	23	1,987,155
Contract wholesale	229,074	35	169,211	678,608	40	486,149
Wholesale off system	321,231	126	141,930	832,742	95	426,143
Total electric sales	1,669,242	63%	1,023,443	3,961,708	37%	2,899,447

Electric Utilities Power Plant Availability

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Coal-fired plants	96.4%	96.6%	93.2%*	95.5%
Other plants	98.7%	99.8%	92.6%	99.6%
Total availability	97.3%	98.0%	93.0%	97.3%

* 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. Prior to the outage, the plant was operating at approximately 85 percent of its rated capacity. The Osage outage was originally scheduled for approximately 10 days and lasted 52 days as a result of additional unplanned required maintenance. The plants were all online by the end of the second quarter.

Electric Utilities
Megawatt Hours Generated and Purchased

	Three Months Ended September 30,			Nine Months Ended September 30,		
Resources	2008	Percentage Change	2007	2008	Percentage Change	2007
Coal	727,614	65%	441,626	1,934,942	47%	1,316,851
Gas	12,381	(64)	34,117	54,212	(21)	68,458
	739,995	56%	475,743	1,989,154	44%	1,385,309
MWhs purchased	1,018,010	71%	595,062	2,134,244	29%	1,650,086
Total resources	1,758,005	64%	1,070,805	4,123,398	36%	3,035,395

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007. Income from continuing operations increased $3.6 million from the prior period primarily due to the following:

Increased gross margins of $23.7 million primarily due to margins of $14.1 million contributed by the recently acquired Colorado Electric, a Cheyenne Light electric and gas rate increase effective January 1, 2008 and reduced purchased power costs as fuel for lower cost power generated by Wygen II replaced higher cost purchased power.

Partially offsetting the increases were the following:

Increased Wygen II operating expenses of $1.5 million and increased depreciation of $1.2 million; and

Operating expenses of $10.5 million of the recently acquired Colorado Electric.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007. Income from continuing operations increased $7.6 million from the prior period primarily due to the following:

Increased gross margins of $45.6 million primarily due to margins of $14.1 million contributed by the acquired electric utility, a Cheyenne Light rate increase in 2008, and reduced purchased power costs as fuel for lower cost power generated by Wygen II replaced higher cost purchased power.

Partially offsetting the increases were the following:

Increased Wygen II operating expenses of $4.3 million and increased depreciation of $3.7 million;

Increased operating expense due to increased repair and maintenance expenses and outside services primarily related to the plant outages and personnel costs; and

Additional operating expenses of $10.5 million of the acquired electric utility.

Gas Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Revenue:				
Natural gas regulated	$ 75,465	$	$ 75,465	$
Other non-regulated	8,472		8,472	
Total Sales	$ 83,937	$	$ 83,937	$
Cost of sales:				
Natural gas regulated	47,364		47,364	
Other non-regulated	5,823		5,823	
Total cost of sales	53,187		53,187	
Gross margin	30,750		30,750	
Operating expenses	29,777		29,777	
Operating income	$ 973	$	$ 973	$
Loss from continuing operations and net income	$ (1,854)	$	$ (1,854)	$

The following tables provide certain operating statistics for the Gas Utilities segment:

	Regulated Gas Utilities Margins (in thousands)	
Customer Base	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Commercial	$ 5,163	$ 5,163
Residential	18,697	18,697
Industrial	3,329	3,329
Total gas	27,189	27,189
Other	912	912
Total gas margins	$ 28,101	$ 28,101

	Dekatherms Sold (in thousands)	
Customer Base	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Commercial	1,235,851	1,235,851
Residential	2,179,902	2,179,902
Industrial	1,755,762	1,755,762
Total gas	5,171,515	5,171,515
Other	10,147	10,147
Total gas margins	5,181,662	5,181,662

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

Sales and volumes for the three month period were at normal levels based on heating degree days.

Rate case was filed in Iowa and interim rates were put into effect in June 2008. Revenues are currently being collected subject to refund. The final decision by the IUB is expected in the third quarter of 2009.

Rate case was filed in Colorado in June 2008, interim rates are not allowed under the ratemaking rules of the CPUC. The final decision and implementation of rates is expected in the second quarter of 2009.

Regulatory Matters

The following summarizes our recent rate case activity:

In millions	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved
Kansas Gas (1)	Gas	11/2006	6/2007	$ 7.2	$ 5.1
Nebraska Gas (2)	Gas	11/2006	9/2007	$ 16.3	$ 9.2
Cheyenne Light (3)	Electric	3/2007	1/2008	$ 8.4	$ 6.7
Cheyenne Light (4)	Gas	3/2007	1/2008	$ 4.6	$ 4.4
Iowa Gas (5)	Gas	6/2008	Pending	$ 13.6	Pending
Colorado Gas (6)	Gas	6/2008	Pending	$ 2.8	Pending
Black Hills Power (7)	Electric	9/2008	12/2008	$ 4.5	Pending

(1) In April 2007, Kansas Gas entered into an agreement that resulted in a black box settlement of $5.1 million, with a residential customer charge of $16 per month that will recover approximately 65 percent of the margin in the customer charge. The KCC approved the settlement in May 2007, and the new rates were implemented on June 1, 2007.

(2) 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 percent on a capital structure of 51 percent equity and 49 percent 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). One aspect of our refund plan worth approximately $0.8 million has been appealed to the district court by the Nebraska Public Advocate.

(3) In November 2007, the WPSC granted a $6.7 million increase in annual electric utility revenues based on an equity return of 10.9 percent on a capital structure of 54 percent equity and 46 percent debt. The new rates were implemented on January 1, 2008. The WPSC also placed the Wygen II power plant into rate base and approved a pass-through mechanism for Cheyenne Light s electric business. Under the pass-through mechanism, the annual increase or decrease for transmission, fuel and purchased power costs is passed through to customers, subject to a $1.0 million threshold. Under its tariff, Cheyenne Light collects or refunds 95 percent of the increase or decrease that exceeds the $1.0 million threshold; for changes below the threshold, Cheyenne Light absorbs the increase or retains the savings.

(4) In November 2007, the WPSC granted a $4.4 million increase in annual gas utility revenues based on an equity return of 10.9 percent on a capital structure of 54 percent equity and 46 percent debt. The new rates were implemented on January 1, 2008.

(5) In June 2008, Iowa Gas filed for a $13.6 million rate increase. The increase is based on a proposed equity return of 11.5 percent on a capital structure of 52 percent equity and 48 percent debt, and interim rates were implemented on June 13, 2008. The IUB has until July 2, 2009 to issue a decision on our rate request. On August 12, 2008, the IUB issued an order that extended the usual ten month time limit for consideration of the general rate increase by three months, from April 2, 2009 to July 2, 2009. If interim rates are different than final approved rates, the difference plus interest will be refunded or credited to customers.

(6) In June 2008, Colorado Gas filed for a $2.8 million rate increase. The increase is based on a proposed equity return of 11.5 percent on a capital structure of 50 percent equity and 50 percent debt. Interim rates are not available for collection in Colorado. On September 19, 2008, Colorado Gas filed the second phase of its rate request. The CPUC has until June 16, 2009 to issue a decision on our rate request.

(7) On September 29, 2008, Black Hills Power requested FERC approval to revise the method used to determine the revenue component of the utility s open access transmission tariff, and increase the utility s annual transmission revenue requirement by approximately $4.5 million. The proposed revenue requirement is based on an equity return of 10.95 percent, and we have requested an effective date of December 1, 2008. The FERC has the authority to delay the effective date of the rates by five months. The determination of delays will be made in late November 2008.

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,	
	2008	2007	2008	2007
	(in thousands)			
Revenue	$ 25,438	$ 24,291	$ 85,770	$ 75,948
Operating expenses	21,285	19,813	63,692	56,799
Operating income	$ 4,153	$ 4,478	$ 22,078	$ 19,149
Income from continuing operations and net income	$ 1,517	$ 1,979	$ 11,266	$ 9,945

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Fuel production:				
Bbls of oil sold	95,248	100,923	298,035	307,816
Mcf of natural gas sold	2,873,353	3,285,222	8,293,364	9,147,245
Mcf equivalent sales	3,444,841	3,890,760	10,081,574	10,994,141

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Average price received: [a]				
Gas/Mcf [b]	$ 5.26	$ 5.35	$ 7.13[c]	$ 6.40
Oil/Bbl	$ 83.86	$ 62.51	$ 88.07	$ 58.82
Depletion expense/Mcfe	$ 2.58	$ 2.41	$ 2.40	$ 2.17

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids
(c) Does not include the revenue impact of a $2.1 million royalty settlement accrual resulting in a $0.27/Mcf price impact

The following are summaries of LOE/Mcfe:

	Three Months Ended September 30, 2008			Three Months Ended September 30, 2007		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.62	$ 0.25	$ 1.87	$ 0.98	$ 0.25	$ 1.23
Colorado	1.22	0.71[a]	1.93	0.40	0.48 [a]	0.88
Wyoming	1.21		1.21	1.04		1.04
All other properties	0.71	0.12	0.83	1.09	0.40	1.49
All locations	$ 1.26	$ 0.20	$ 1.46	$ 0.99	$ 0.23	$ 1.22

	Nine Months Ended September 30, 2008			Nine Months Ended September 30, 2007		
Location	LOE	Gathering, Compression and Processing	Total	LOE	Gathering, Compression and Processing	Total
New Mexico	$ 1.51	$ 0.29	$ 1.80	$ 0.99	$ 0.33	$ 1.32
Colorado	1.17	0.80[a]	1.97	0.97	0.76 [a]	1.73
Wyoming	1.54		1.54	1.15		1.15
All other properties	0.89	0.10	0.99	0.81	0.22	1.03
All locations	$ 1.33	$ 0.21	$ 1.54	$ 0.98	$ 0.25	$ 1.23

(a) Reflects the expenses associated with Colorado acquisitions completed in 2006 which included underutilized gathering, processing and compression assets. The Company anticipates that future development of these properties will increase the capacity utilization rate of these gathering and processing assets and the per unit costs will decrease.

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007. Income from continuing operations decreased $0.5 million for the three months ended September 30, 2008 compared to the same period in 2007 primarily due to:

A $0.5 million increase in LOE due to increased fuel and service costs;

A $1.1 million increase in production taxes due to higher oil prices; and

A higher effective income tax rate due to approximately $0.8 million in income tax adjustments resulting from amended federal income tax returns and other tax accrual adjustments.

Partially offsetting these increased expenses were the following:

Revenue increased $1.1 million due to a 34 percent increase in the average hedged price of oil received partially offset by a 2 percent decrease in average hedged price of gas received and lower production of 11 percent. The lower production reflects permitting delays, the temporary shut-in of Piceance Basin gas production and delayed drilling activities on our non-operated properties; and

Reduced interest expense of $1.0 million primarily due to lower interest rates.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007. Income from continuing operations increased $1.3 million for the nine months ended September 30, 2008 compared to the same period in 2007 primarily due to:

Revenue increased $9.8 million due to a 50 percent increase in the average hedged price of oil received and an 11 percent increase in average hedged price of gas received, partially offset by an 8 percent decrease in production and the impact of a royalty settlement with the Jicarilla Apache Nation. The lower production reflects weather impacts in the San Juan Basin early in the year, ongoing federal drilling permit delays, primarily in the Piceance Basin, the temporary shut-in of Piceance Basin gas production and delays in drilling activities on our non-operated properties; and

Reduced interest expense of $2.3 million primarily due to lower interest rates.

Partially offsetting these increases were the following:

A $2.7 million increase in LOE due to costs related to severe weather conditions in New Mexico, the expansion of field compression capacity and increased fuel costs;

A $4.3 million increase in production taxes due to higher oil and gas prices; and

A higher effective income tax rate due to approximately $1.8 million in income tax adjustments resulting from amended federal income tax returns and other tax accrual adjustments.

Coal Mining

	Three Months Ended September 30, 2008 (in thousands)	2007	Nine Months Ended September 30, 2008	2007
Revenue	$ 16,031	$ 10,446	$ 41,925	$ 30,192
Operating expenses	14,210	9,300	38,556	26,010
Operating (loss) income	$ 1,821	$ 1,146	$ 3,369	$ 4,182
Income from continuing operations and net income	$ 1,092	$ 1,358	$ 3,217	$ 4,353

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

	Three Months Ended September 30, 2008 (in thousands)	2007	Nine Months Ended September 30, 2008	2007
Tons of coal sold	1,521	1,314	4,518	3,796
Cubic yards of overburden moved	3,368	2,188	9,021	5,402

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007.

Income from continuing operations from our Coal Mining segment for the three months ended September 30, 2008 decreased $0.3 million compared to the same period in the prior year. Results were impacted by the following:

Operating expenses increased $4.9 million, or 53 percent, during the three months ended September 30, 2008 primarily due to increased overburden removal costs, an increase in diesel fuel costs, increased coal taxes due to a higher revenue base and increased depreciation due to increased equipment usage. We produced a 54 percent increase in cubic yards of overburden moved. This contributed to a $1.8 million increase in overburden costs, which was partially offset by the capitalization of overburden required for a conveyor extension. In accordance with GAAP, we expense overburden removal costs when incurred, which may not coincide with the timing of revenues from the sale of the tons of coal that were uncovered.

Partially offsetting the increased expenses was the following:

Revenue increased $5.6 million, or 53 percent, for the three month period ended September 30, 2008 compared to the same period in 2007. Revenues increased due to an increase in average price received and higher quantity of tons of coal sold, primarily due to additional sales to Cheyenne Light for Wygen II and increased train load-out sales.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007.

Income from continuing operations from our Coal Mining segment for the nine months ended September 30, 2008 decreased $1.1 million compared to the same period in the prior year. Results were impacted by the following:

Operating expenses increased $12.5 million, or 48 percent, during the nine months ended September 30, 2008 primarily due to increased overburden removal costs, an increase in diesel fuel costs, increased coal taxes due to a higher revenue base and increased depreciation due to increased equipment usage. We produced a 67 percent increase in cubic yards of overburden moved. This contributed to a $4.4 million increase in overburden costs, which was partially offset by the capitalization of overburden required for a conveyor extension. In accordance with GAAP, we expense overburden removal costs when incurred, which may not coincide with the timing of revenues from the sale of the tons of coal that were uncovered.

Partially offsetting the increased expenses was the following:

Revenue increased $11.7 million, or 39 percent, for the nine month period ended September 30, 2008 compared to the same period in 2007. Revenues increased due to an increase in average price received and higher quantity of tons of coal sold, primarily due to additional sales to Cheyenne Light for Wygen II and increased train load-out sales.

Energy Marketing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Revenue				
Realized gas marketing gross margin	$ (4,477)	$ 17,661	$ 3,384	$ 58,016
Unrealized gas marketing gross margin	26,889	(5,453)	24,418	3,504
Realized oil marketing gross margin	(1,856)	1,615	2,472	3,722
Unrealized oil marketing gross margin	(1,360)	50	191	(22)
	19,196	13,873	30,465	65,220
Operating expenses	9,026	10,476	19,506	28,529
Operating income	$ 10,170	$ 3,397	$ 10,959	$ 36,691
Income from continuing operations and net income	$ 6,902	$ 2,290	$ 7,565	$ 23,886

The following is a summary of average daily volumes marketed:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Natural gas physical sales MMBtus	1,854,100	1,859,100	1,749,600	1,779,400
Crude oil physical sales Bbls	7,800	10,200	7,300	9,000

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007. Income from continuing operations increased $4.6 million due to:

A $30.9 million pre-tax increase in unrealized marketing margins; and

Lower incentive compensation costs related to the decreased realized gas marketing margins.

Partially offsetting these increases were the following:

A $22.1 million pre-tax decrease in realized gas marketing margins primarily resulting from prevailing conditions in natural gas markets affecting both transportation and storage strategies. Realized crude oil marketing margins were lower due to the impact of decreasing commodity prices on inventory held to meet pipeline requirements. Our crude oil marketing strategy has been enhanced by our investment in proprietary pipeline injection stations which have allowed us to deliver customized services to crude oil producers with greater margin potential.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007. Income from continuing operations decreased $16.3 million due to:

A $54.6 million pre-tax decrease in realized gas marketing margins primarily resulting from prevailing conditions in natural gas markets affecting both transportation and storage strategies. The Rockies Express Pipeline s west segment was placed into service during the first quarter of 2008 resulting in a compressed Rocky Mountain basis spread, which contributed to the decrease in margin over the first half of the year. In addition, realized crude oil marketing margins were lower due to the impact of decreasing commodity prices on inventory held to meet pipeline requirements and a 19 percent decrease in crude oil marketed;

Partially offsetting these decreases was the following:

A $21.1 million pre-tax increase in unrealized marketing margins; and

Lower incentive compensation costs related to the decreased realized gas marketing margins.

Power Generation

On July 11, 2008, the Company completed the sale of seven of its IPP plants with 974 MW of capacity to affiliates of Hastings and IIF. Results of operations for the following retained plants continue to be reported in the Power Generation segment:

Asset (State)	Capacity (net megawatts)
Wygen I (Wyoming)*	90
Gillette CT (Wyoming)	40
Ontario Cogeneration (California)**	12
Rupert and Glenns Ferry Cogeneration (Idaho)***	11
Power fund investments (various locations)	5
Total	158

* Mine-mouth coal-fired base load generation
** Decommissioning of this plant is expected by the end of 2008 or early 2009
*** Capacity represents the Company s 50 percent interest in the two power plants

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Revenue	$ 11,704	$ 10,048	$ 29,079	$ 30,123
Operating expenses	4,338	11,307	18,877	28,798
Operating income	$ 7,366	$ (1,259)	$ 10,202	$ 1,325
Income (loss) from continuing operations	$ 3,197	$ (900)	$ 1,698	$ (1,850)

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,	
	2008	2007	2008	2007
Contracted power plant fleet availability:				
Coal-fired plant	96.8%	95.3%	95.6%	94.3%
Other plants	99.4%	94.7%	82.5%	85.5%
Total availability	97.8%	95.0%	94.8%	94.9%

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007. Income from continuing operations increased $4.1 million and was impacted by:

The sale of nitrogen oxide (NOx) Reclaim Trading Credits allocated to our Ontario facility for $1.7 million after-tax;

Equity in earnings of unconsolidated subsidiaries of approximately $1.3 million and $0.4 million for the three months ended September 31, 2008 and 2007, respectively;

The recording of an impairment loss, and related costs, in the third quarter of 2007 of $1.8 million after-tax relating to the Ontario plant; and

Allocated indirect corporate costs and inter-segment interest expense, including costs related to the IPP assets sold and not reclassified to discontinued operations, of $3.2 million after-tax for the three months ended September 30, 2007.

Partially offsetting these increases were the following:

Earnings from the Wygen I and Gillette CT II plants were $1.7 million and $3.1 million for the three months ended September 30, 2008 and 2007, respectively, primarily due to increased interest costs partially offset by lower fuel and purchased gas costs in 2008; and

A higher income tax rate resulting from amended federal income tax returns.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007. Income from continuing operations increased $3.5 million and was impacted by:

The sale of nitrogen oxide (NOx) Reclaim Trading Credits allocated to our Ontario facility for $1.7 million after-tax;

Equity in earnings of unconsolidated subsidiaries of approximately $3.2 million and $1.3 million for the nine months ended September 30, 2008 and 2007, respectively;

The recording of an impairment loss, and related costs, in the third quarter of 2007 of $1.8 million after-tax relating to the Ontario plant; and

Allocated indirect corporate costs and inter-segment interest expense, including costs related to the IPP assets sold and not reclassified to discontinued operations, of $7.7 million and $9.1 million after-tax for the nine months ended September 30, 2008 and 2007, respectively. These costs were historically allocated to the Power Generation segment, but will be allocated in future periods to reflect the recent changes in our business and asset mix.

Partially offsetting these increases were the following:

Earnings from the Wygen I and Gillette CT II plants were $8.2 million and $10.0 million for the nine months ended September 30, 2008 and 2007, respectively, primarily due to increased interest costs partially offset by lower fuel and purchased power costs in 2008.

Corporate

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007. Losses increased $1.3 million due to increased unallocated costs in the three months ended September 30, 2008, compared to the same period in 2007, primarily due to additional incentive compensation costs related to the IPP Transaction and Aquila Transaction.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007. Losses increased $6.2 million due to increased unallocated costs in the nine months ended September 30, 2008, compared to the same period in 2007, primarily as a result of increased transition and integration costs and additional incentive compensation costs related to the IPP Transaction and Aquila Transaction. Partially offsetting the cost increases were $2.3 million in after-tax proceeds from an earlier sale of development rights in a power plant project. This represents payments that were contingent upon the occurrence of certain agreed-upon terms for permitting and construction progress.

Discontinued Operations

Earnings from discontinued operations were $145.4 million for the three month period ended September 30, 2008, compared to $6.3 million for the same period in 2007. The 2008 results contain $141.7 million of net income attributable to the after-tax gain on the sale of the IPP assets that closed on July 11, 2008.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2007 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 2007 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the nine month period ended September 30, 2008, we generated sufficient cash flow from operations to meet our operating needs and to pay dividends on our common stock. We utilized borrowings on our revolving credit facility to pay our scheduled long-term debt maturities and to fund a portion of our property, plant and equipment additions. Our July 14, 2008 acquisition of certain electric and gas utility assets of Aquila for $940 million, subject to customary closing adjustments, was financed through a $383 million borrowing on our $1 billion acquisition credit facility and from cash proceeds generated from our July 11, 2008 sale of the IPP assets. Cash flow activity for 2008 includes cash flows of the utility assets purchased, from the date of acquisition. We plan to fund future property and investment additions including the construction costs of the 100 MW Wygen III generation facility located near Gillette, Wyoming from internally generated cash resources and external financings.

Cash flows from operations of $80.1 million for the nine month period ended September 30, 2008 represent a $125.6 million decrease compared to the same period in the prior year due to a $13.1 million decrease in income from continuing operations and from the following:

A $111.5 million decrease in cash flows from working capital changes. This decrease primarily resulted from a $72.3 million decrease in cash flows from a net purchase of materials, supplies and fuel. This is primarily related to natural gas held in storage by Energy Marketing and the Gas Utilities which fluctuates based on economic decisions reflecting current market conditions;

A $16.6 million decrease in cash flows from the net change in derivative assets and liabilities, primarily from derivatives associated with normal operations of Energy Marketing and our Oil and Gas segment related to commodity price fluctuations;

A $66.5 million increase in cash flows related to changes in deferred income taxes which is primarily the result of the inclusion in prior year deferred income taxes of a deferred income tax benefit attributable to amended federal tax returns and an increase in deferred income taxes related to tax planning strategies implemented in connection with the IPP Transaction; and

A $17.4 million increase in depreciation, depletion and amortization.

During the nine months ended September 30, 2008, we had cash outflows from investing activities of

$357.8 million, which were primarily due to the following:

Cash outflows of $219.4 million for property, plant and equipment additions. These outflows include approximately $76.4 million related to the construction of our Wygen III power plant and approximately $65.6 million in oil and gas property maintenance capital and development drilling;

Cash outflows of $937.6 million for the acquisition of utility assets;

Cash outflows of $29.0 million for discontinued operations, primarily related to construction costs of the Valencia power plant, which was included in the IPP asset sale; and

Cash outflows of $6.5 million for short-term investments primarily related to Auction Rate Securities held and previously classified as cash and cash equivalents.

Partially offset by:

Cash inflows of $835.3 million proceeds from the sale of the IPP assets.

During the nine months ended September 30, 2008, we had net cash inflows from financing activities of $354.7 million, primarily due to:

- $208.0 million net borrowings of funds from our revolving credit facility; and
- $382.8 million borrowings on the Acquisition Credit Facility.

Partially offset by:

- Repayment of $130.3 million of long-term debt, including $128.3 million for the Wygen I project debt;
- Repayment of $73.9 million for the Colorado project debt, which was part of the IPP Transaction; and
- The payment of cash dividends on common stock.

Dividends

On September 1, 2008 we paid a dividend of $0.35 per common share, equivalent to an annual dividend rate of $1.40 per share. Dividends paid on our common stock totaled $40.2 million during the nine months ended September 30, 2008, or $1.05 per share. Additionally, at its October 29, 2008 meeting, our Board of Directors declared a quarterly dividend of $0.35 per common share to all shareholders of record on November 14, 2008 which is payable December 1, 2008. 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 facility 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, 2008, we had approximately $152.5 million of cash unrestricted for operations.

<u>Corporate Credit Facility</u>

On July 10, 2008, borrowing capacity on our revolving credit facility was increased from $400 million to $525 million. Our 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 0.70 basis points over LIBOR (which equates to a 4.63 percent one-month borrowing rate as of September 30, 2008).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At September 30, 2008, we had borrowings of $245.0 million and $34.3 million of letters of credit issued on our revolving credit facility. Available capacity remaining on our revolving credit facility was approximately $245.7 million at September 30, 2008.

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 percent of our aggregate consolidated net income beginning January 1, 2005;

a recourse leverage ratio not to exceed 0.65 to 1.00, (or 0.70 to 1.00 for the first year after the Aquila acquisition); 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.

A default under the credit facility may be triggered by events such as a failure to comply with financial covenants or certain other covenants under the credit facility, 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. A default under the credit facility would permit the participating banks to restrict our ability to further access the credit facility for loans or new letters of credit, require the immediate repayment of any outstanding loans with interest and require 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 $1,149.2 million at September 30, 2008, which was approximately $315.7 million in excess of the net worth we were required to maintain under the credit facility. Our long-term debt ratio at September 30, 2008 was 30.4 percent, our total debt leverage (long-term debt and short-term debt) was 49.6 percent, our recourse leverage ratio was approximately 51.9 percent and our interest expense coverage ratio for the twelve month period ended September 30, 2008 was 7.89 to 1.0.

Enserco Credit Facility

Enserco, our Energy Marketing segment, has a $300 million uncommitted, discretionary line of credit to provide support for the purchase and sale of natural gas and crude oil through the issuance of letters of credit. The line of credit is secured by all of Enserco s assets. At September 30, 2008, there were outstanding letters of credit issued under the facility of $143.8 million, with no borrowing balances outstanding on the facility. This credit facility expires May 8, 2009.

The Enserco credit facility may be impacted by the current global credit crisis. The credit crisis is prompting most commercial banks to reduce their commitments, or deleverage their portfolios. Consequently, some of the Enserco credit facility participating banks may decline to participate in new credit transactions under the facility. Should a bank decline to participate in the facility, the existing issued letters of credit would remain in place. The available capacity of the $300 million Enserco facility, however, would be reduced by that bank s pro rata participation under the facility for future transactions.

The two largest participating banks under our $300 million Enserco credit facility are Fortis Capital Corp. and BNP Paribas, having participation levels of $105 million and $75 million, respectively. On September 29, 2008, after the deterioration in the financial strength of the Fortis bank group, the governments of Belgium, Luxembourg and the Netherlands agreed to invest EUR 11.2 billion in Fortis. In conjunction with the announcement, the senior unsecured credit ratings of Fortis Bank SA/NV, the entity which issues letters of credit under the Enserco credit facility, were reduced from Aa3 to A1 by Moody s, and from A+ to A by Standard and Poor s.

On October 6, 2008 BNP Paribas announced that it had agreed to acquire control of Fortis operations in Belguim and Luxembourg, as well as the international banking franchises, which includes Fortis Capital Corp; the participating bank in the Enserco credit facility. Closing on the transaction is subject to antitrust and regulatory approvals, and is expected to take place by year end or in the first quarter of 2009.

Upon completion of the acquisition of Fortis by Paribas, it is expected that the two entities will continue to operate as stand-alone entities for a certain period of time. It is uncertain, however, as to whether the two entities, either before or after the acquisition is effected, will continue to participate in the Enserco facility at their current levels.

Because of the uncommitted nature of the Enserco facility, and given the current condition of credit markets, we are conducting our Enserco business operations in a manner to conserve our utilization of the facility. We intend to pursue a committed credit facility for Enserco to replace the current facility upon its May 8, 2009 expiration.

2008 Financing Transactions

On May 7, 2007, we entered into a senior unsecured $1.0 billion Acquisition Facility with ABN AMRO Bank N.V. as administrative agent and other banks to provide for funding for our acquisition of Aquila s electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa. The Acquisition Facility is a committed facility to fund an acquisition term loan in a single draw in an amount up to $1.0 billion. On July 14, 2008, in conjunction with the completion of the purchase of the Aquila properties, we executed a single draw of $383 million under the Acquisition Facility; no additional borrowing capacity is thus available under the acquisition facility. The loan termination date is February 5, 2009.

Borrowings under the Acquisition Facility can be made under a base rate option, which is based on the then-current prime rate, or under a LIBOR option, which is based on the then-current LIBOR plus an applicable margin. The applicable margin for LIBOR borrowings is 55 basis points during the period from the initial funding under the term loan to six months thereafter and 67.5 basis points during the period from six months and one day after the initial funding to the loan maturity. The facility contains certain customary affirmative and negative covenants which largely replicate the covenants under our existing revolving credit facility.

We initially funded the payment for our June 2008 project debt maturity of $128.3 million on the Wygen I facility through borrowings on our revolving credit facility.

In conjunction with the sale of the IPP assets, the $67.5 million project financing debt for our Colorado facility was paid off.

Future Financing Plans

We previously planned to complete a senior unsecured long-term holding company debt offering of $450 million or more in the fourth quarter of 2008, with a portion of the proceeds to be used to pay off the $383 million borrowing on the Acquisition Facility, and the remaining proceeds used to reduce borrowings on the revolving credit facility. The current global financial crisis has caused a widespread contraction in the availability of credit from the commercial bank markets and debt capital markets, as well as a sharp increase in credit risk premiums.

Because of the increase in long-term credit risk premiums and the reduction in capacity in the debt capital markets, we are reviewing and considering other alternatives to a senior unsecured long-term holding company debt offering. Those alternatives include an extension of all or a portion of the Acquisition Facility borrowing to a maturity date of late 2009 or later, or a new term loan in the amount of $200 million or more, with a one to three year maturity date. In the interim, we continue to prepare for and include as a financing alternative a long-term debt issuance, which will be evaluated based upon further developments in the debt capital markets.

If we are unable to complete a replacement debt financing or an extension of the Acquisition Facility financing, 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. If we cannot complete capital conservation or capital raising alternatives at sufficient levels, we may be unable to repay all or a portion of the $383 million Acquisition Facility loan, which is due on February 5, 2009.

Interest Rate Swaps

The Company has forward starting interest rate swaps with a notional amount of $250.0 million. These swaps were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were designated as cash flow hedges in accordance with SFAS 133 and at September 30, 2008, they had a mark-to-market value of $(28.1) million, which was recorded in Accumulated other comprehensive loss on the Condensed Consolidated Balance Sheet.

Subsequent to September 30, 2008, based on credit market conditions that transpired in October, the Company determined that the forecasted long-term debt financings were no longer probable of occurring. The Company continues to evaluate its near term financing alternatives, which may include long-term financings and/or the use of other financing alternatives with a shorter duration. As a result of the originally forecasted long-term financings no longer being probable of occurring within the originally specified time period, the swaps were no longer effective hedges in accordance with SFAS 133 and hedge relationships were de-designated. On the date of de-designation, the swaps had a mark-to-market value of approximately $(42.7) million. This value will remain in Accumulated other comprehensive loss and subsequent mark-to-market adjustments to the swaps will be recorded within the income statement.

These subsequent mark-to-market adjustments could have a significant impact on our results of operations. A 100 basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $31.7 million. Should the Company complete a long-term financing with terms that are closely correlated to the hedged forecasted transactions, then the amount in Accumulated other comprehensive loss will be amortized and recorded as interest expense over the term of the underlying debt. If the Company determines that the long-term financing is probable of not occurring by the end of the originally specified time period, the balance in Accumulated other comprehensive loss related to the swaps will be immediately recorded as a charge to earnings.

Counterparty Credit Risk

Another risk arising from current global financial conditions is increased potential for exposure to counterparty credit default. We have established guidelines, controls, and limits to manage and mitigate credit risk. For our energy marketing, production and generation activities, we seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements. Through this current credit crisis we have been aggressively observing and evaluating any changes in our counterparties credit status and adjusting the credit limits based upon the customer s current creditworthiness. Through this aggressive monitoring, we have been able to avoid any significant credit losses during the current credit crisis.

On September 14th, 2008, Lehman Brothers Holdings Inc. (Lehman) and several of its subsidiaries filed for bankruptcy. Enserco has physical and financial gas transactions with Lehman Energy Commodity Services, Inc., (LECS), a Lehman subsidiary. Enserco has approximately $0.4 million in money owed to Enserco by LECS for forward mark-to-market natural gas financial transactions. Enserco owes LECS approximately $0.4 million for forward physical natural gas transactions. The Company believes it has setoff rights among the transactions; in the event the Company was not able to execute setoff rights, the Company would have a loss exposure of $0.4 million pretax.

Corporate Credit Rating Update

Our corporate credit rating by Moody s was Baa3 during the first six months of 2008; on July 15, 2008, Moody s revised the outlook of our credit rating from negative to stable. Our corporate credit rating by S&P was BBB-; the outlook is stable. On July 15, 2008 we received a BBB issuer default rating from Fitch.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2007 Annual Report on Form 10-K filed with the SEC.

Capital Requirements

During the nine months ended September 30, 2008, capital expenditures were approximately $244.9 million for property, plant and equipment additions, which were partially financed through approximately $25.5 million of accrued liabilities. We currently expect total capital expenditures for 2008, excluding the Aquila asset acquisition, to approximate $401.0 million. This sum includes, but is not limited to: $27.8 million related to the Valencia 149 MW, simple-cycle gas turbine generating facility located near Albuquerque, New Mexico which was sold as part of the IPP asset sale; $76.2 million for the 100 MW Wygen III power plant located near Gillette, Wyoming (with the assumption we retain 75 percent ownership in the plant); $56.3 million related to maintenance capital for our new utility properties; $17.0 million for the acquisition of non-operated oil and gas interests; and $84.1 million within our Oil and Gas segment primarily for maintenance capital and development drilling.

As result of the current global credit crisis we are re-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.

Forecasted capital requirements for maintenance capital and development capital are as follows:

	Nine Months Ended September 30, 2008 Expenditures (in thousands)	Total 2008 Planned Expenditures
Utilities: (1)		
Electric Utilities Wygen III(2)	$ 76,427	$ 79,321
Electric Utilities (3)(4)	46,243	116,247(6)
Gas Utilities(4)	12,188	35,773
Non-regulated Energy:		
Oil and Gas(4)	62,420	84,100
Power Generation - Valencia(5)	27,847	30,600
Power Generation	1,661	5,802(6)
Coal Mining	16,820	22,070
Energy Marketing	21	135
Corporate (including Aquila acquisition costs)	26,098	27,000
	$ 269,725	$ 401,048

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(1) Forecasted capital requirements are exclusive of the $940.0 million purchase price and related other costs for the acquisition of Aquila utility assets in 2008.
(2) Forecasted expenditures of the Wygen III coal-fired plant reflect our expectation that we will retain a 75 percent ownership interest in the plant.
(3) Electric Utilities capital requirements include approximately $17.2 million for transmission projects in 2008.
(4) Capital expenditures include expenditures of the acquired utilities subsequent to the acquisition date.
(5) The Valencia power plant was included in the IPP assets sold July 11, 2008.
(6) Forecasted capital requirements include $8.0 million of project costs for air-cooled condenser upgrades for our Neil Simpson II and Wygen I coal-fired plants. Total project costs are expected to be approximately $16.2 million and will add approximately 8.2 MW of rated capacity to each plant. This represents additional base load installed capacity at approximately $995 per kilowatt.

Contractual Obligations

Unconditional purchase obligations for firm transportation and storage fees for our Energy Marketing segment increased $44.9 million from $47.9 million at December 31, 2007 to $92.8 million at September 30, 2008. Approximately $47.8 million of the fee obligations relate to the 2009-2011 period with the remaining occurring thereafter.

See Note 14 to our consolidated financial statements for purchase obligations related to our acquired utilities.

In addition, contractual obligations of $14.0 million related to the IPP plants sold consisted of $12.7 million of land lease obligations for the Arapahoe, Valmont and Harbor power plants and $1.3 million for a Las Vegas II transmission agreement. These obligations were previously reported as purchase obligations in the Liquidity section of Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, in our 2007 Annual Report on Form 10-K.

Guarantees

See Note 6 to our consolidated financial statements.

New Accounting Pronouncements

Other than the new pronouncements reported in our 2007 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 issued that when implemented would require us to either retroactively restate prior period financial statements or record a cumulative catch-up adjustment.

FORWARD-LOOKING INFORMATION

This report contains forward-looking information. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. The forward-looking statements contained in this report include:

We expect to refinance in the bank loan markets or the debt capital markets the acquisition debt we incurred in the Aquila Transaction before the acquisition loan matures in the first quarter of 2009. 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 remain tight and do not improve, we may not be able to permanently finance our acquisition debt 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 permanently finance the acquisition debt 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 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 forecast 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.

§ Access to our uncommitted $300 million Enserco facility depends on the willingness of the participating banks to continue to participate in extensions of credit requested under the facility. Given the ongoing credit crisis, participating banks could decide to stop participating in the facility.

In connection with the IPP Transaction, we expect to defer tax payments in the range of $135 million to $160 million. Some important factors that could cause actual results to differ materially from those anticipated include:

§ The IRS could challenge and rule against our deferred tax strategies, which could impair our ability to defer all or part of these tax payments.

We expect to sell to MDU a minority interest in our Wygen III project under construction. Some important factors that could cause actual results to differ materially from those anticipated include:

§ We have not entered into definitive transaction agreements with MDU with respect to the proposed sale transaction. If we are not able to reach an agreement with MDU on the terms and conditions upon which the sale would be consummated, we will not be able to complete the anticipated sale transaction.

§ In the event we enter into definitive transaction agreements with MDU, we or MDU may not be able to satisfy one or more of the conditions required to complete the sale transaction.

We expect to complete the sale of a minority interest in Wygen I to MEAN this year. Some important factors that could cause actual results to differ materially from those anticipated include:

§ MEAN may not be able to arrange the acquisition financing required to complete the announced sale transaction.

§ We or MEAN may not be able to satisfy one or more of the other conditions required to be satisfied in order to consummate the sale transaction.

We intend to replace the uncommitted $300 million Enserco facility with a committed credit facility prior to its May 2009 expiration date. Some important factors that could cause actual results to differ materially from those anticipated include:

§ Our ability to access the bank loan market depends on market conditions beyond our control. If the credit environment remains tight and does not improve, we may not be able to replace the uncommitted facility with a committed credit line on reasonable terms, if at all.

§ Our ability to obtain a committed credit facility for Enserco upon reasonable terms, if at all, may depend on, among other factors, our ability to pledge Enserco assets or otherwise provide credit support to lenders willing to participate in a committed credit facility.

We expect to make contributions to our defined benefit contribution plans of approximately $14.5 million in 2009. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

§ The actual value of the plans invested assets at December 31, 2008.

§ The discount rate used in determining the funding requirement.

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 purchased gas adjustment (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 Colorado, Montana, South Dakota, and Wyoming, 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 at September 30, 2008 are summarized below (in thousands):

	September 30, 2008
Net derivative assets (liabilities)	$ 9,424
Cash collateral	12,750
	$ 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, 2008 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2007	$	3,718 [(a)]
Net cash settled during the period on positions that existed at December 31, 2007		19,389
Change in fair value due to change in assumptions		1,898
Unrealized gain on new positions entered during the period and still existing at September 30, 2008		44,269
Realized loss on positions that existed at December 31, 2007 and were settled during the period		(26,413)
Change in cash collateral[(b)]		(502)
Unrealized gain on positions that existed at December 31, 2007 and still exist at September 30, 2008		(13,807)
Total fair value of energy marketing positions at September 30, 2008	$	28,552 [(a)]

(a) The fair value of energy marketing positions consists of derivative assets/liabilities held at fair value in accordance with SFAS 157 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 SFAS 133, as follows (in thousands):

	September 30, 2008	June 30, 2008	March 31, 2008	December 31, 2007
Net derivative assets (liabilities)	$ 45,392	$ (1,606)	$ (8,475)	$ 14,797
Cash collateral	(1,789)	49,050	32,876	(1,287)
Market adjustment recorded in material, supplies and fuel	(15,051)	6,312	4,551	(9,792)
	$ 28,552	$ 53,756	$ 28,952	$ 3,718

(b) The Company adopted FSP FIN 39-1 effective January 1, 2008. See Note 2 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative under SFAS 133. 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, SFAS 133 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.

We adopted the provisions of SFAS 157 on January 1, 2008. SFAS 157 provides a single definition of fair value and establishes a fair value hierarchy which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. We use the fair value methodology outlined in SFAS 157 to value the assets and liabilities for our outstanding derivative contracts. See Note 12 of the 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):

	Maturities		
Source of Fair Value	Less than 1 year	1 2 years	Total Fair Value
Level 1	$ (1,789)	$	$ (1,789)
Level 2	41,310	1,536	42,846
Level 3	4,995	(2,449)	2,546
Market value adjustment for inventory (see footnote (a) above)	(15,051)		(15,051)
Total	$ 29,465	$ (913)	$ 28,552

The following table presents a reconciliation of our September 30, 2008 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)	$ 28,552
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	87,614
Fair value of all forward positions (non-GAAP)	116,166
Cash collateral included in GAAP marked-to-market fair value	1,789
Fair value of all forward positions excluding cash collateral (non-GAAP)	$ 117,955

There have been no material changes in market risk faced by us from those reported in our 2007 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 2007 Annual Report on Form 10-K, and Note 12 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Activities Other Than Trading

The Company has entered into agreements to hedge a portion of its estimated 2008, 2009 and 2010 natural gas and crude oil production from the Oil and Gas business segment. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term		Volume (MMBtu/day)	Price	
San Juan El Paso	11/29/2006	Swap	01/08	12/08	5,000	$	7.44
San Juan El Paso	11/29/2006	Swap	11/07	12/08	3,000	$	7.49
San Juan El Paso	01/04/2007	Swap	04/08	03/09	2,500	$	6.93
San Juan El Paso	01/04/2007	Swap	04/08	03/09	1,000	$	6.96
San Juan El Paso	01/05/2007	Swap	01/09	03/09	1,500	$	7.51
San Juan El Paso	01/10/2007	Swap	04/08	12/08	1,500	$	6.88
San Juan El Paso	01/11/2007	Swap	04/08	12/08	2,000	$	6.81
San Juan El Paso	02/12/2007	Swap	01/09	03/09	5,000	$	7.87
San Juan El Paso	04/25/2007	Swap	04/09	06/09	2,500	$	7.21
San Juan El Paso	04/26/2007	Swap	04/09	06/09	2,500	$	7.15
San Juan El Paso	05/09/2007	Swap	04/09	06/09	5,000	$	7.24
CIG	05/09/2007	Swap	04/09	06/09	2,000	$	6.87
CIG	05/09/2007	Swap	01/09	03/09	2,000	$	8.37
San Juan El Paso	07/27/2007	Swap	07/09	09/09	5,000	$	7.63
CIG	09/07/2007	Swap	07/09	09/09	1,500	$	6.48
CIG	09/07/2007	Swap	04/08	12/08	1,500	$	5.91
AECO	09/07/2007	Swap	04/08	10/09	1,000	$	6.89
San Juan El Paso	10/29/2007	Swap	07/09	09/09	5,000	$	7.38
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	11/16/2007	Basis Swap	04/08	12/08	-1,500	$	(0.93)
NWR	11/16/2007	Basis Swap	04/08	12/08	1,500	$	(1.64)
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
AECO	01/23/2008	Swap	04/08	12/08	1,000	$	6.87
San Juan El Paso	02/28/2008	Swap	01/10	03/10	3,000	$	8.55
AECO	02/28/2008	Swap	04/08	10/08	1,000	$	8.37
CIG	02/28/2008	Swap	04/08	10/08	1,000	$	7.73
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

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	01/30/2007	Swap	Calendar 2008	5,000	$ 61.38
NYMEX	02/20/2007	Put	Calendar 2008	5,000	$ 60.00
NYMEX	03/07/2007	Swap	Calendar 2008	5,000	$ 67.34
NYMEX	03/23/2007	Swap	01/09 03/09	5,000	$ 67.60
NYMEX	03/26/2007	Put	Calendar 2008	5,000	$ 63.00
NYMEX	03/28/2007	Swap	01/09 03/09	5,000	$ 69.00
NYMEX	04/12/2007	Put	01/09 03/09	5,000	$ 65.00
NYMEX	04/26/2007	Swap	04/09 06/09	5,000	$ 70.25
NYMEX	05/10/2007	Swap	04/09 06/09	5,000	$ 69.10
NYMEX	05/29/2007	Put	04/09 06/09	5,000	$ 65.00
NYMEX	06/22/2007	Swap	07/09 09/09	5,000	$ 72.10
NYMEX	07/27/2007	Put	07/09 09/09	5,000	$ 65.00
NYMEX	09/12/2007	Swap	07/09 09/09	5,000	$ 71.20
NYMEX	09/12/2007	Put	01/09 03/09	5,000	$ 70.00
NYMEX	09/12/2007	Put	04/09 06/09	5,000	$ 70.00
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	07/09 09/09	5,000	$ 75.00
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	10/24/2008	Put	10/10 12/10	5,000	$ 60.00

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, 2008. 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 have materially affected or are reasonably likely to materially affect our internal control over financial reporting. On July 14, 2008, we acquired the assets of Aquila s regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa (the Acquired Businesses). The internal controls of the Acquired Businesses are an area of focus for us. We are in the process of reviewing the internal controls of the Acquired Businesses and making any necessary changes. As permitted by the guidance set forth by the Securities and Exchange Commission, the Acquired Businesses will not be included in management s assessment of internal control over financial reporting for the year ending December 31, 2008.

Part II Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 18 in Item 8 of our 2007 Annual Report on Form 10-K and Note 14 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 14 is incorporated by reference into this item.

Item 1A. Risk Factors

Except as set forth below, there have been no material changes in risk factors involving us from those previously disclosed in Item 1A. of Part I in our Annual Report on Form 10-K for the year ended December 31, 2007.

Recent events in the global financial crisis have made the credit markets less accessible and created a shortage of available credit. We may, therefore, be unable to obtain the financing needed to refinance debt, fund planned capital expenditures, or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent on our having access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt, and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings, and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in electricity or natural gas prices, and general economic and market conditions.

Recent financial distress within the global economy has caused significant disruption in the credit markets. Among other things, long-term interest rates on debt securities have increased significantly and the volume of equity and debt security issuances has decreased. Recent actions taken by the United States government, the Federal Reserve and other governmental and regulatory bodies may be insufficient to stabilize these markets. The longer such conditions persist, the more significant the implications become for the Company, including the potential that adequate capital is not available (or available on reasonable commercial terms) for us to refinance the $383 million borrowing on the Acquisition Facility or to replace our uncommitted $300 million Enserco facility with a committed credit line. If we are unable to (i) timely refinance the $383 million borrowing or extend its maturity date or (ii) replace the existing uncommitted Enserco facility with a committed credit line, or both, we could be required to consider additional measures to conserve or raise capital. Among other things, alternatives could include deferring portions of our planned capital expenditure program, selling assets, issuing equity, reducing or eliminating our dividend, or curtailing certain business activities, including our marketing operations. Moreover, if we cannot complete capital conservation or capital raising alternatives at sufficient levels on a timely basis, we may not be able to repay all or a portion of the $383 million borrowing that must be repaid on February 5, 2009. In addition, we have in place forward starting interest rate swaps associated with the anticipated long-term debt issuance. If the anticipated long-term debt issuance does not occur as planned, the accounting treatment of the interest rate swaps may be impacted. The failure to consummate these anticipated refinancings, and any actions taken in lieu of such refinancings, could have a material adverse effect on our results of operations, cash flows and financial condition.

In addition, given that the Company is a holding company and that our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. These alternatives would be evaluated in the context of market conditions then-prevailing, prudent financial management, and any applicable regulatory requirements.

Recent events in the global financial crisis have also increased our counterparty credit risk.

As a consequence of the global financial crisis, the creditworthiness of numerous contractual counterparties (particularly financial institutions) has deteriorated. As the creditworthiness of our counterparties deteriorates, we face increased exposure to counterparty credit default. For example, as a result of the Lehman bankruptcy filing, we have a pre-tax exposure of $0.4 million to a Lehman entity if we are not able to setoff certain financial and physical natural gas transactions we have with the Lehman entity.

We have established guidelines, controls, and limits to manage and mitigate credit risk. For our energy marketing, production and generation activities, we seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements. Although we aggressively monitor and evaluate changes in our counterparties credit status and adjust the credit limits based upon changes in the customer s current creditworthiness, there are no assurances that our credit guidelines, controls, and limits will protect us from increasing counterparty credit risk under today s stressed financial conditions. To the extent the financial crisis causes our credit exposure to contractual counterparties to increase materially, such increased exposure could have a material adverse effect on our results of operations, cash flows and financial condition.

National and regional economic conditions may cause increased late payments and uncollectible accounts, which would reduce earnings and cash flows.

Recent concerns over inflation, energy costs, the availability and cost of credit, and increased unemployment have contributed to an economic slowdown and fears of recession. These factors could lead to an increase in late payments from utility customers and uncollectible accounts could increase, which could materially reduce our earnings and cash flows.

Our credit ratings could be lowered below investment grade in the future. If this were to occur, it could impact our access to capital, our cost of capital and our other operating costs.

Our issuer credit rating is Baa3 , with a stable outlook by Moody s and BBB- , with a stable outlook by S&P. Although we believe the IPP Transaction and Aquila Transaction have strengthened our financial profile and creditworthiness, we cannot provide assurances that our credit ratings will not be lowered. If our credit ratings are lowered, it could impair our ability to refinance or repay our existing debt (including debt incurred to fund part of the Aquila purchase price) and to complete new financings on acceptable terms, if at all. A downgrade could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and, therefore, recoverable.

Our regulated electricity and natural gas operations are subject to cost-of-service regulation and earnings oversight. This regulatory treatment does not provide any assurance as to achievement of earnings levels. Our rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our gas and electric utilities in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota, and Wyoming is permitted to recover certain costs (such as increased fuel and purchased power costs, as applicable) without having to file a rate case. To the extent we pass through such costs to ratepayers and a state public utility commission subsequently determines that such costs should not have been paid by ratepayers, we may be required to refund such costs to ratepayers. Any such costs not recovered through rates could negatively affect our revenues.

Our operating results can be adversely affected by milder weather.

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, and demand for natural gas is extremely sensitive to winter weather effects on space heating requirements. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our utility operations have historically generated less revenues and income when weather conditions are cooler in the summer and warmer in the winter. We expect that unusually mild summers and winters could have an adverse effect on our financial condition and results of operations.

We may not be able to effectively integrate the utility operations acquired from Aquila into our existing businesses and operations, or achieve the anticipated results.

We expect our recent acquisition of Aquila properties to produce various benefits. Achieving the anticipated benefits of the acquisition is subject to a number of uncertainties, such as pending and future rate cases and operational and financial synergies. We cannot provide assurances that the businesses we acquired from Aquila will be integrated in an efficient and effective manner, or that they will be profitable after our integration efforts have been completed.

Our energy marketing and utility operations rely on storage and transportation assets owned by third parties to satisfy their obligations.

Our energy marketing operations involve contracts to buy and sell natural gas, crude oil, and other commodities, many of which are settled by physical delivery. We depend on pipelines and other storage and transportation facilities owned by third parties to satisfy our delivery obligations under these contracts. Our gas utility businesses also rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to ratepayers and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered. As a result, we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates, or for penalties imposed by state regulatory authorities.

We rely on cash distributions from our subsidiaries to make and maintain dividends and debt payments. Our subsidiaries may not be able or permitted to make dividend payments or loan funds to us.

We are a holding company. Our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary s ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital or debt service funds.

Our utility operations are regulated by state utility commissions in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota, and Wyoming. In connection with the Aquila Transaction, the settlement agreements or acquisition orders approved by the CPUC, IUB, KCC, and NPSC provide that, among other things, (i) our utilities in those jurisdictions cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40 percent of their total capitalization; (ii) neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to us except in the ordinary course of business and upon reasonable terms consistent with market terms. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including intercompany loans. If our utility subsidiaries are unable to pay dividends or advance funds to us as a result of these conditions, or if the ability of our utility subsidiaries to make dividends or advance funds to us is further restricted, it could materially and adversely affect our ability to meet our financial obligations or pay dividends to our shareholders.

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

We own regulated and unregulated coal-fired power plants in Colorado, South Dakota, and Wyoming, and we are constructing another coal-fired power plant in Wyoming. Air emissions of coal-fired power plants are subject to federal and state regulation. Recent changes in federal and state laws governing air emissions from coal-burning power plants will result in more stringent emission limitations. As the issue of climate change, particularly with respect to CO_2 emissions by coal-fired power plants, receives increased attention, further emission limitations could be imposed. To the extent our coal-fired power plants are included in rate base, we will attempt to recover costs associated with complying with emission standards; however, there can be no assurance that we will be permitted to recover such compliance costs in customer rates. Nor can we provide assurance that the emission compliance costs of our non-regulated coal-fired power plants will be recoverable from utility and other purchasers of the power generated by our non-regulated power plants. In addition, future changes in environmental regulations governing air pollutants could render some of our electric 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 renewable portfolio standards that require electric utilities to source a minimum percentage of the power delivered to customers 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 (and could increase materially). Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to fully recover such costs.

We have recorded a substantial amount of goodwill associated with our recently completed acquisition. Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net income and shareholders equity.

We had approximately $401 million of goodwill recorded on our consolidated balance sheet as of September 30, 2008. A substantial portion of the goodwill is related to our recently completed acquisition within our Utilities Group. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net income. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, regulatory, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge.

A sustained decline in our common stock price below book value may result in goodwill impairments that could adversely affect our results of operations and financial position, and could, under current market conditions inhibit our access to capital and could result in a downgrade to our credit ratings.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	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, 2008 July 31, 2008	106 [1]	$ 35.69		
August 1, 2008 August 31, 2008	155	$ 32.87		
September 1, 2008 September 30, 2008	36	$ 34.30		
Total	297	$ 34.05		

(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 and the exercise of stock options.

Item 6. Exhibits

Exhibit 31.1	Certification 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 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 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 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 10, 2008

EXHIBIT INDEX

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