BLACK HILLS CORP /SD/
Form 10-Q
November 09, 2006

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, 2006.

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES 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 or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer	x	Accelerated filer	o	Non-accelerated filer	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, 2006
Common stock, $1.00 par value	33,313,142 shares

TABLE OF CONTENTS

		Page
PART I.	FINANCIAL INFORMATION	
Item 1.	Financial Statements	
	Condensed Consolidated Statements of Income Three and Nine Months Ended September 30, 2006 and 2005	3
	Condensed Consolidated Balance Sheets September 30, 2006, December 31, 2005 and September 30, 2005	4
	Condensed Consolidated Statements of Cash Flows Nine Months Ended September 30, 2006 and 2005	5
	Notes to Condensed Consolidated Financial Statements	6-36
Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations	37-59
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	60-62
Item 4.	Controls and Procedures	62
PART II.	OTHER INFORMATION	
Item 1.	Legal Proceedings	63
Item 1A.	Risk Factors	63
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	63
Item 6.	Exhibits	64
	Signatures	65
	Exhibit Index	66

BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(in thousands, except per share amounts)			
Operating revenues	$ 157,608	$ 149,008	$ 483,312	$ 433,813
Operating expenses:				
Fuel and purchased power	47,740	49,758	151,150	134,849
Operations and maintenance	16,490	18,014	60,566	55,071
Administrative and general	19,721	21,669	64,776	60,403
Depreciation, depletion and amortization	24,141	22,039	67,407	62,362
Taxes, other than income taxes	8,570	8,869	26,667	25,483
Project development cost write - off		8,931		9,495
Impairment of long-lived assets		50,279		50,279
	116,662	179,559	370,566	397,942
Operating income (loss)	40,946	(30,551)	112,746	35,871
Other income (expense):				
Interest expense	(12,400)	(11,089)	(37,310)	(36,421)
Interest income	389	331	1,403	1,294
Other income, net	106	139	517	819
	(11,905)	(10,619)	(35,390)	(34,308)
Income (loss) from continuing operations before equity in earnings of unconsolidated subsidiaries, minority interest and income taxes	29,041	(41,170)	77,356	1,563
Equity in earnings of unconsolidated subsidiaries	615	3,434	(16)	7,788
Minority interest	(95)	(74)	(273)	(199)
Income tax (expense) benefit	(7,362)	14,026	(23,939)	(2,367)
Income (loss) from continuing operations	22,199	(23,784)	53,128	6,785
Income (loss) from discontinued operations, net of taxes	81	(119)	7,060	22
Net income (loss)	22,280	(23,903)	60,188	6,807
Preferred stock dividends				(159)
Net income (loss) available for common stock	$ 22,280	$ (23,903)	$ 60,188	$ 6,648
Weighted average common shares outstanding:				
Basic	33,187	32,967	33,157	32,660
Diluted	33,560	32,967	33,526	33,100
Earnings (loss) per share:				
Basic				
Continuing operations	$ 0.67	$ (0.73)	$ 1.60	$ 0.20
Discontinued operations			0.21	
Total	$ 0.67	$ (0.73)	$ 1.81	$ 0.20
Diluted				

Continuing operations	$ 0.66	$ (0.73)	$ 1.59	$ 0.20
Discontinued operations			0.21	
Total	$ 0.66	$ (0.73)	$ 1.80	$ 0.20
Dividends paid per share of common stock	$ 0.33	$ 0.32	$ 0.99	$ 0.96

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

3

BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)

	September 30, 2006	December 31, 2005	September 30, 2005
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 47,716	$ 31,817	$ 46,060
Restricted cash			700
Receivables (net of allowance for doubtful accounts of $4,007; $4,685 and $4,317, respectively)	195,571	264,695	240,110
Materials, supplies and fuel	91,490	122,521	179,387
Derivative assets	66,990	20,681	33,184
Income tax receivable	11,524		
Deferred income taxes			6,803
Other assets	7,830	7,842	6,666
Assets of discontinued operations	1,043	122,158	119,019
	422,164	569,714	631,929
Investments	23,709	27,558	24,906
Property, plant and equipment	2,180,639	1,928,559	1,898,313
Less accumulated depreciation and depletion	(574,925)	(518,525)	(510,401)
	1,605,714	1,410,034	1,387,912
Other assets:			
Derivative assets	3,197	1,898	4,722
Goodwill	30,563	29,847	28,455
Intangible assets (net of accumulated amortization of $25,072; $22,734 and $21,954, respectively)	25,209	27,548	28,328
Other	38,177	53,646	47,391
	97,146	112,939	108,896
	$ 2,148,733	$ 2,120,245	$ 2,153,643
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 181,255	$ 202,639	$ 192,202
Accrued liabilities	82,098	72,514	71,610
Derivative liabilities	18,937	26,141	114,941
Deferred income taxes	5,001	1,443	
Notes payable	147,000	55,000	42,000
Current maturities of long-term debt	17,103	11,771	11,690
Accrued income taxes		11,650	16,022
Liabilities of discontinued operations	4,131	92,818	86,720
	455,525	473,976	535,185
Long-term debt, net of current maturities	632,295	670,193	672,770
Deferred credits and other liabilities:			
Deferred income taxes	170,286	134,533	128,798
Derivative liabilities	2,913	2,623	6,096
Other	101,819	95,116	90,853
	275,018	232,272	225,747
Minority interest in subsidiaries	5,198	4,925	5,034
Stockholders equity:			
Common stock equity			
Common stock $1 par value; 100,000,000 shares authorized; Issued 33,330,841; 33,222,522 and 33,200,699 shares, respectively	33,331	33,223	33,201

Additional paid-in capital	407,488	404,035	403,822
Retained earnings	338,420	313,217	297,204
Treasury stock at cost 34,720; 66,938 and 73,805 shares, respectively	(883)	(1,766)	(1,909)
Accumulated other comprehensive income (loss)	2,341	(9,830)	(17,411)
	780,697	738,879	714,907
	$ 2,148,733	$ 2,120,245	$ 2,153,643

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

4

BLACK HILLS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(unaudited)

	Nine Months Ended September 30, 2006	2005
	(in thousands)	
Operating activities:		
Income from continuing operations	$ 53,128	$ 6,785
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	67,407	62,362
Impairment of long-lived assets		50,279
Net change in derivative assets and liabilities	2,136	2,894
Deferred income taxes	32,042	(17,617)
Distributed earnings in associated companies	4,304	1,954
Change in operating assets and liabilities, net of acquisition-		
Materials, supplies and fuel	(6,389)	(19,058)
Accounts receivable and other current assets	59,005	(14,068)
Accounts payable and other current liabilities	(61,878)	39,932
Other operating activities	26,239	15,489
Net cash provided by operating activities of continuing operations	175,994	128,952
Net cash (used in) provided by operating activities of discontinued operations	(1,583)	5,276
Net cash provided by operating activities	174,411	134,228
Investing activities:		
Property, plant and equipment additions	(153,820)	(86,897)
Proceeds from sale of assets		103,010
Payment for acquisition, net of cash acquired	(75,425)	(67,331)
Other investing activities	(454)	5,615
Net cash used in investing activities of continuing operations	(229,699)	(45,603)
Net cash provided by (used in) investing activities of discontinued operations	40,160	(6,966)
Net cash used in investing activities	(189,539)	(52,569)
Financing activities:		
Dividends paid	(32,954)	(31,612)
Common stock issued	3,560	12,822
Increase in short-term borrowings, net	92,000	18,000
Long-term debt issuances	90,000	
Long-term debt repayments	(122,566)	(91,675)
Other financing activities	(1,171)	(730)
Net cash provided by (used in) financing activities of continuing operations	28,869	(93,195)
Net cash used in financing activities of discontinued operations		
Net cash provided by (used in) financing activities	28,869	(93,195)
Increase (decrease) in cash and cash equivalents	13,741	(11,536)
Cash and cash equivalents:		
Beginning of period	34,198*	64,507**
End of period	$ 47,939*	$ 52,971**
Supplemental disclosure of cash flow information:		
Non-cash investing and financing activities-		
Property, plant and equipment acquired with accrued liabilities	$ 31,481	$ 9,711
Cash paid during the period for-		
Interest	$ 35,317	$ 31,551
Net income taxes paid	$ 12,806	$ 2,403

____

*Includes approximately $0.2 million at September 30, 2006 and $2.4 million at December 31, 2005 of cash included in discontinued operations.

**Includes approximately $6.9 million at September 30, 2005 and $8.6 million at December 31, 2004 of cash included in 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 2005 Annual Report on Form 10-K)

(1) MANAGEMENT S STATEMENT

The financial statements included herein have been prepared by Black Hills Corporation (the Company) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. 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 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission (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, 2006, December 31, 2005 and September 30, 2005 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 natural gas is sensitive to seasonal heating and industrial load requirements, as well as changes in market price. The results of operations for the three and nine months ended September 30, 2006, 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.

(2) RECLASSIFICATIONS

Certain 2005 amounts in the financial statements have been reclassified to conform to the 2006 presentation. These reclassifications include reflecting a net presentation for derivative assets and liabilities that are subject to master netting agreements which provide for the legal right of offset of amounts due to and due from the same counterparty under the agreement. At September 30, 2005, current derivative assets and current derivative liabilities on the accompanying Condensed Consolidated Balance Sheet have been reduced by approximately $133.5 million and non-current derivative assets and non-current derivative liabilities have been reduced by approximately $1.7 million to reflect the legal right of offset and conform to the December 31, 2005 and September 30, 2006 presentation. These reclassifications did not have an effect on the Company s total stockholders equity or net income available for common stock as previously reported.

(3) RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

SFAS No. 123 (Revised 2004)

On December 16, 2004, the Financial Accounting Standards Board, or FASB, issued FASB Statement No. 123 (Revised 2004) Share-Based Payment, or SFAS 123(R), which is a revision of SFAS Statement No. 123, Accounting for Stock-Based Compensation (SFAS 123). SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

The Company previously accounted for its employee equity compensation stock option plans under the provisions of APB No. 25 and no stock-based employee compensation cost is reflected in net income for the three and nine month periods ended September 30, 2005 for stock options.

As of January 1, 2006, the Company applied the provisions of SFAS 123(R) using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption and for the unvested portion of previously granted awards that were outstanding at the date of adoption. Adoption of SFAS 123(R) did not have a significant effect on the Company s consolidated financial position, results of operations or cash flows. See Note 11, Common Stock, for further discussion of stock-based compensation plans.

EITF Issue No. 04-6

On March 17, 2005, the Emerging Issues Task Force (EITF) issued EITF Issue No. 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry (EITF 04-6). EITF 04-6 provides that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005. Upon adoption of EITF 04-6 on January 1, 2006, the Company recorded a $2.0 million cumulative effect adjustment to write-off previously recorded deferred charges, with the offset decreasing retained earnings. Additionally, since January 1, 2006, stripping costs are expensed at the time incurred.

EITF Issue No. 04-13

On September 28, 2005 the FASB ratified the consensus reached under EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, (EITF 04-13) which determines if such transactions should be reported on a gross basis or a net basis.

EITF 04-13 is effective for new arrangements entered into, and modifications or renewals of existing arrangements, in reporting periods beginning after March 16, 2006. The adoption did not have a significant effect on the Company s consolidated financial position, results of operations or cash flows.

7

(4) RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

SFAS No. 157

During September 2006 the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (SFAS 157) and applies under other accounting pronouncements that require or permit fair value measurements. This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Management is currently evaluating the impact SFAS 157 will have on the Company s consolidated financial statements.

SFAS No. 158

During September 2006 the FASB issued Statement of Financial Accounting Standards No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R) (SFAS 158). This Statement requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position, and provides for related disclosures. SFAS 158 is effective for the recognition of the funded status as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, and the related disclosures in financial statements issued for fiscal years ending after December 15, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 will require the measurement of the funded status of the plan to coincide with the date of the year end statement of financial position. Management is currently evaluating the impact SFAS 158 will have on the Company s consolidated financial statements.

FIN 48

During June 2006 the FASB issued FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109 Accounting for Income Taxes (FAS 109) and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the impact of adoption to be reported as a cumulative effect of an accounting change. Management is currently evaluating the impact FIN 48 will have on the Company s consolidated financial statements.

SAB No. 108 Effects of Prior Year Misstatements on Current Year Financial Statements

During September 2006 the staff of the SEC released SAB No. 108 on Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 provides guidance on how the effects of the carryover or reversal of prior year financial statement misstatements should be considered in quantifying a current year misstatement. Prior practice allowed the evaluation of materiality on the basis of (1) the error quantified as the amount by which the current year income statement was misstated (rollover method) or (2) the cumulative error quantified as the cumulative amount by which the current year balance sheet was misstated (iron curtain method). Reliance on either method in prior years could have resulted in misstatement of the financial statements. The guidance provided in SAB No. 108 requires both methods to be used in evaluating materiality. Immaterial prior year errors may be corrected with the first filing of prior year financial statements after adoption. The cumulative effect of the correction can either be reported in the carrying amounts of assets and liabilities as of the beginning of that fiscal year, and the offsetting adjustment made to the opening balance of retained earnings for that year, or by restating prior periods. Appropriate disclosure of the nature and amount of each individual error being corrected in the cumulative adjustment, as well as a disclosure of when and how each error being corrected arose and the fact that the errors had previously been considered immaterial. SAB No. 108 is effective January 1, 2007. Management is currently evaluating the impact this bulletin might have on the Company s consolidated financial statements.

(5) 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, 2006	December 31, 2005	September 30, 2005
Materials and supplies	$ 30,160	$ 24,567	$ 24,435
Fuel	9,387	7,544	8,745
Gas held by energy marketing*	51,943	90,410	146,207
Total materials, supplies and fuel	$ 91,490	$ 122,521	$ 179,387

* As of September 30, 2006, December 31, 2005 and September 30, 2005, market adjustments related to natural gas held by energy marketing and recorded in inventory were $(29.8) million, $6.6 million and $61.0 million, respectively.

The gas inventory held by the Company s energy marketing subsidiary is held under various contractual storage arrangements. The 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. A substantial majority of the gas was economically hedged at the time of purchase either through a fixed price physical or financial forward sale.

(6) LONG-TERM DEBT AND GUARANTEES

On July 12, 2006 the Company s subsidiary, Black Hills Colorado, LLC, entered into a Second Amended and Restated Credit Agreement to refinance the floating rate project debt for the Valmont and Arapahoe plants in the amount of $90.0 million. The maturity date of the amortizing borrowings is July 2013. In conjunction with the refinancing, the Company made a payment in the amount of $21.3 million on the $111.3 million principal outstanding at June 30, 2006 and expensed approximately $0.7 million of unamortized deferred finance costs associated with the First Amended and Restated Credit Agreement. In addition, as of July 12, 2006, the Company has guaranteed during the term of the debt the payment obligations of Black Hills Colorado, LLC, to the Bank of Nova Scotia, as administrative agent under the Credit Agreement, for up to $30 million. The cost of borrowings under the facility is determined based upon the Company s corporate credit ratings; at the current ratings levels, the facility has a borrowing spread on Eurodollar loans of 87.5 basis points over LIBOR (which equates to a 6.25 percent, three-month borrowing rate as of September 30, 2006).

On May 24, 2006 the Company entered into an Amended and Restated Credit Agreement for the project financing floating rate debt for Wygen I. The agreement extended the maturity date of the $111.1 million tranche of the financing from June 2006 to June 2008 to coincide with the maturity date of the remaining $17.2 million tranche. The cost of borrowings under the financing is determined based upon the Company s corporate credit ratings; at the Company s current ratings levels, the financing has a borrowing spread on Eurodollar loans of 62.5 basis points over LIBOR (which equates to a 5.95 percent, one-month borrowing rate as of September 30, 2006). In conjunction with the Amended and Restated Credit Agreement, the Company entered into an Amended and Restated Guarantee in favor of Wygen Funding, Limited Partnership, which continues the Company s guarantee obligations under the Wygen I plant lease.

In addition to the guarantees discussed above, during the nine months ended September 30, 2006 the Company had the following changes to its guarantees:

Issued and amended a Guarantee for payment under various transactions by Cheyenne Light with Tenaska Marketing Ventures for $2.0 million, expiring in 2007.

Extinguished a guarantee of up to $3.0 million of Enserco Energy Inc. s obligations to Fortis Capital Corp. and other lenders under its credit facility.

Expiration of a guarantee of an interest rate swap transaction with Union Bank of California.

At September 30, 2006, we had guarantees totaling $187.9 million in place.

(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, 2006	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 22,199		$ 53,128	
Basic available for common shareholders	22,199	33,187	53,128	33,157
Dilutive effect of:				
Stock options		91		85
Estimated contingent shares issuable for prior acquisition		158		158
Others		124		126
Diluted available for common shareholders	$ 22,199	33,560	$ 53,128	33,526

Period ended September 30, 2005	Three Months		Nine Months	
	Income	Average Shares	Income	Average Shares
Income (loss) from continuing operations	$ (23,784)		$ 6,785	
Less: preferred stock dividends			(159)	
Basic available for common shareholders	(23,784)	32,967	6,626	32,660
Dilutive effect of:				
Stock options				164
Estimated contingent shares issuable for prior acquisition				158
Others				118
Diluted available for common shareholders	$ (23,784)	32,967	$ 6,626	33,100

(8) COMPREHENSIVE INCOME

The following table presents the components of the Company s comprehensive income (loss)

(in thousands):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Net income (loss)	$ 22,280	$ (23,903)	$ 60,188	$ 6,807
Other comprehensive income (loss), net of tax:				
Fair value adjustment on derivatives designated as cash flow hedges	7,425	(11,095)	12,587	(15,260)
Reclassification adjustments on cash flow hedges settled and included in net income	(246)	3,262	(416)	5,441
Unrealized gain on available-for-sale securities				15
Comprehensive income (loss)	$ 29,459	$ (31,736)	$ 72,359	$ (2,997)

(9) INCOME TAXES

The Company s effective tax rates differ from the federal statutory rate as follows:

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	35.0%	35.0%	35.0%	35.0%
State income tax	0.3	1.1	0.5	(2.1)
Percentage depletion in excess of cost	(1.5)	0.7	(1.3)	(6.0)
IRS exam tax adjustment*	(7.3)		(2.8)	
Tax return true-up	(1.3)	1.5	(0.5)	(4.5)
Other	(0.3)	(1.2)	0.2	3.5
	24.9%	37.1%	31.1%	25.9%

____

* As a result of the settlement of an Internal Revenue Service (IRS) exam of the tax years 2001-2003 with respect to certain tax positions taken by the Company, a reduction to income tax expense of approximately $2.2 million was recorded in the third quarter of 2006.

(10) PROCEEDS RECEIVED ON INSURANCE CLAIMS

In late 2005 and the first half of 2006, the Company s Las Vegas II power plant experienced unplanned outages due to damage to three of its gas turbines and two of its steam turbines. The outages lasted approximately six months as repairs were made to the turbines. The Company has filed insurance claims for reimbursement of repair expenditures and business interruption losses in the amount of approximately $11.1 million. At September 30, 2006, the Company has provided for the receipt of insurance proceeds of approximately $4.3 million. Approximately $0.4 million was applied to reduce capitalized repair costs included in Property, plant and equipment on the accompanying Condensed Consolidated Balance Sheet and $2.2 million for repair costs and $1.7 million for business interruption were applied as a reduction to Operations and maintenance expense on the accompanying Condensed Consolidated Statement of Income. While the Company is pursuing additional reimbursement from the insurance carrier, the carrier asserts that certain deductibles, exclusions and limitations apply preventing any future claims reimbursements. There can be no assurance that the Company will obtain any additional recovery from the insurance carrier.

(11) COMMON STOCK

Equity Compensation Plans

The Company has several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. The Company has 1,082,894 shares available to grant at September 30, 2006.

At September 30, 2006, the Company had one stock-based employee compensation plan under which it can grant stock options to its employees and three prior plans with stock options outstanding. Prior to January 1, 2006, the Company accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB 25), and related interpretations. Prior to 2006, no stock-based compensation expense related to stock options was reflected in net income as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. However, the Company did recognize stock-based compensation expense for other non-vested share awards including restricted stock and restricted stock units, performance shares and directors phantom shares.

The following table illustrates the effect on net income (loss) and earnings (loss) per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation (in thousands, except per share amounts):

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net (loss) income available for common stock, as reported	$ (23,903)	$ 6,648
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(126)	(389)
Pro forma net income available for common stock	$ (24,029)	$ 6,259
Earnings (loss) per share:		
Basic as reported		
Continuing operations	$ (0.73)	$ 0.20
Discontinued operations		
Total	$ (0.73)	$ 0.20
Diluted as reported		
Continuing operations	$ (0.73)	$ 0.20
Discontinued operations		
Total	$ (0.73)	$ 0.20
Basic pro-forma		
Continuing operations	$ (0.73)	$ 0.19
Discontinued operations		
Total	$ (0.73)	$ 0.19
Diluted pro-forma		
Continuing operations	$ (0.73)	$ 0.19
Discontinued operations		
Total	$ (0.73)	$ 0.19

On January 1, 2006 the Company adopted the fair value recognition provisions of SFAS 123(R) requiring the recognition of expense related to the fair value of stock-based compensation awards. The Company elected the modified prospective transition method. Under this method, compensation expense is recognized for all stock-based awards granted prior to, but not yet vested as of January 1, 2006 and all stock-based awards granted subsequent to January 1, 2006. Adoption of SFAS 123(R) did not have a material effect on the Company s consolidated financial position, results of operations or cash flows. Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of SFAS 123(R) and is recognized over the vesting periods of the individual plans. Total stock-based compensation expense for the three months ended September 30, 2006 and 2005 was $0.1 million ($0.1 million, after tax) and $1.1 million ($0.7 million, after tax), respectively, and for the nine months ended September 30, 2006 and 2005 was $1.8 million ($1.2 million, after tax) and $3.1 million ($2.0 million, after tax), respectively, and is included in administrative and general expense on the accompanying Condensed Consolidated Statements of Income. In accordance with the modified prospective transition method of SFAS 123(R), financial results for prior periods have not been restated. As of September 30, 2006, total unrecognized compensation expense related to stock options and other non-vested stock awards is $3.5 million and is expected to be recognized over a weighted-average period of 1.8 years.

In November 2005, the FASB issued FASB Staff Position (FSP) No. FAS 123 (R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. FSP 123(R)-3 provides an alternative method of calculating the excess tax benefits available to absorb tax deficiencies recognized subsequent to the adoption of SFAS 123(R). The calculation of excess tax benefits reported as an operating cash outflow and a financing inflow in the Consolidated Statements of Cash Flows required by FSP No. 123(R)-3 differs from that required by SFAS 123(R). The Company has until January 1, 2007 to make a one-time election to adopt the transition method described in FSP No. 123 (R)-3. The Company is currently evaluating FSP No. FAS 123 (R)-3; however, the one-time election is not expected to affect the Company s results of operations.

Stock Options

The Company has granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest one-third each year for three years and expire after ten years from the grant date.

A summary of the status of the stock option plans at September 30, 2006 is as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at January 1, 2006	854	$ 29.56		
Granted	15	33.17		
Forfeited/cancelled	(18)	33.53		
Expired				
Exercised	(71)	27.99		
Balance at September 30, 2006	780	$ 29.68	5.5	$ 3,066
Exercisable at September 30, 2006	680	$ 29.58	5.1	$ 2,739

The weighted-average grant-date fair value of options granted during the nine months ended September 30, 2006 and 2005 was $3.79 and $6.93, respectively. The total intrinsic value of options (the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option) exercised during the nine months ended September 30, 2006 and 2005 was $0.5 million and $5.1 million, respectively. The total fair value of shares vested during each of the nine months ended September 30, 2006 and 2005 was $0.4 million and $0.7 million, respectively.

The fair value of share-based awards is estimated on the date of grant using the Black-Scholes option pricing model. The fair value is affected by the Company s stock price as well as a number of assumptions. The assumptions used to estimate the fair value of share-based awards are as follows:

Valuations Assumptions[1]	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Weighted average risk-free interest rate[2]	4.94%	3.90%
Weighted average expected price volatility[3]	21.54%	42.27%
Weighted average expected dividend yield[4]	3.98%	4.17%
Expected life in years[5]	7	7

[1] Forfeitures are estimated using historical experience and employee turnover.

[2] Based on treasury interest rates with terms consistent with the expected life of the options.

[3] Based on a blended historical and implied volatility of the Company s stock price in 2006 and historical volatility only in 2005.

[4] Based on the Company s historical and expectation of future dividend payouts and may be subject to substantial change in the future.

[5] Based upon historical experience.

Net cash received from the exercise of options for the nine months ended September 30, 2006 and 2005 was $2.0 million and $10.0 million, respectively. The tax benefit realized from the exercise of shares granted for the nine months ended September 30, 2006 and 2005 was $0.2 million and $1.8 million, respectively, and was recorded as an increase to equity.

As of September 30, 2006, there was $0.3 million of unrecognized compensation expense related to stock options that is expected to be recognized over a weighted-average period of 0.9 years.

Restricted Stock and Restricted Stock Units

The fair value of restricted stock and restricted stock unit awards equals the market price of the Company s stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest one-third per year over three years, contingent on continued employment. Compensation cost related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and non-vested restricted stock units at September 30, 2006 is as follows:

	Stock And Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Balance at January 1, 2006	90	$ 30.71
Granted	42	35.20
Vested	(37)	29.33
Forfeited	(2)	32.12
Balance at September 30, 2006	93	$ 33.25

The weighted-average grant-date fair value of restricted stock and restricted stock units granted in the nine months ended September 30, 2006 and 2005 was $35.20 and $30.03, per share, respectively. The total fair value of shares vested during the nine months ended September 30, 2006 and 2005 was $1.3 million and $1.2 million, respectively.

As of September 30, 2006, there was $2.0 million of unrecognized compensation expense related to non-vested restricted stock and non-vested restricted stock units that is expected to be recognized over a weighted-average period of 1.9 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on the Company s total shareholder return over designated performance periods as measured against a selected peer group. In addition, the Company s stock price must also increase during the performance periods.

Participants may earn additional performance shares if the Company s total shareholder return exceeds the 50th percentile of the selected peer group. The final value of the performance shares may vary according to the number of shares of common stock that are ultimately granted based upon the performance criteria.

Outstanding Performance Periods at September 30, 2006 are as follows:

Grant Date	Performance Period	Target Grant of Shares (in thousands)
March 1, 2004	March 1, 2004 December 31, 2006	23
January 1, 2005	January 1, 2005 December 31, 2007	39
January 1, 2006	January 1, 2006 December 31, 2008	34

The performance awards are paid 50 percent in cash and 50 percent in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as temporary equity. In the event of a change-in-control performance awards are paid 100 percent in cash. If it is ever determined that a change-in-control is probable, the equity portion will be reclassified as a liability. At September 30, 2006, the Company had $0.6 million of temporary equity.

A summary of the status of the Performance Share Plan at September 30, 2006 and changes during the nine-month period ended September 30, 2006, is as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average September 30, 2006 Fair Value
Balance at January 1, 2006	38	$ 29.95	38	
Granted	17	32.06	17	
Forfeited	(1)	29.95	(1)	
Vested	(6)	29.92	(6)	
Balance at September 30, 2006	48	$ 30.70	48	$ 23.61

The weighted-average grant-date fair value of performance share awards granted in the nine months ended September 30, 2006 and 2005 was $32.06 and $29.97, per share, respectively. The grant date fair value for the performance shares granted in 2006 was determined by Monte Carlo simulation using a blended volatility of 21 percent comprised of 50 percent historical volatility and 50 percent implied volatility and the average risk-free interest rate of the three-year U.S. Treasury security rate in effect as of the grant date. The grant date fair value for the performance shares issued in 2005 was equal to the market value of the common stock on the grant date.

During the nine months ended September 30, 2006, the Company issued 11,667 shares of common stock and paid $0.4 million for the Performance Period of March 1, 2004 to December 31, 2005, for a total intrinsic value of $0.8 million. The payout was fully accrued at December 31, 2005.

As of September 30, 2006, there was $1.2 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.8 years.

Other Plans

The Company issued 36,685 shares of common stock with an intrinsic value of $910,000 in the nine months ended September 30, 2006 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2005.

(12) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has two 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, LLC, Black Hills Power, Inc., Wyodak Resources Development Corp., and Black Hills Exploration and Production, Inc. The other Plan covers employees of the Company s subsidiary, Cheyenne Light, Fuel and Power Company, who meet certain eligibility requirements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Service cost	$ 649	$ 576	$ 1,947	$ 1,728
Interest cost	1,041	995	3,123	2,985
Expected return on plan assets	(1,247)	(1,157)	(3,741)	(3,471)
Amortization of prior service cost	38	54	114	162
Amortization of net loss	227	296	681	888
Net periodic benefit cost	$ 708	$ 764	$ 2,124	$ 2,292

The Company made a $1.2 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2006; no additional contributions are anticipated to be made to the Plans during the 2006 fiscal year.

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,	
	2006	2005	2006	2005
Service cost	$ 87	$ 86	$ 261	$ 258

Interest cost		270		252		810		756
Amortization of prior service cost		3		2		9		6
Amortization of net loss		199		157		597		471
Net periodic benefit cost	$	559	$	497	$	1,677	$	1,491

The Company anticipates that it will need to make contributions to the Supplemental Plans for the 2006 fiscal year of approximately $0.7 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,	
	2006	2005	2006	2005
Service cost	$ 164	$ 185	$ 492	$ 555
Interest cost	203	232	609	696
Amortization of net transition obligation	38	37	114	111
Amortization of prior service cost	(6)	(6)	(18)	(18)
Amortization of net loss		25		75
Net periodic benefit cost	$ 399	$ 473	$ 1,197	$ 1,419

The Company anticipates that it will make contributions to the Healthcare Plans for the 2006 fiscal year of approximately $0.2 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 is as follows (in thousands):

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006
Service cost	$ (25)	$ (75)
Interest cost	(28)	(84)
Amortization of net loss	(18)	(54)
Total decrease to net periodic postretirement benefit cost	$ (71)	$ (213)

20

(13) IMPAIRMENT TESTING OF OIL AND NATURAL GAS PROPERTIES

The Company s oil and gas segment follows the full cost method of accounting for its oil and gas properties. Under the full cost method, costs related to acquisition, exploration and development drilling activities are capitalized. The net capitalized costs are subject to a ceiling test that limits these costs to the estimated present value of future net revenues from proved reserves based on a single day s spot market prices, and the lower of cost or fair value of unproved properties. Rules mandated by the Securities and Exchange Commission require that future net revenues be based on end-of-period spot market prices, with consideration for alternate prices only to the extent provided for by contractual arrangements, and discounted at a 10 percent interest rate. If the net capitalized costs exceed the full cost ceiling at period end, a permanent non-cash write-down would be required to be charged to earnings in that period unless subsequent market price changes eliminate or reduce the indicated write-down.

In accordance with the Company s full cost method of accounting for its oil and gas properties, we conducted our quarterly ceiling test as of September 30, 2006. Spot market prices for natural gas, particularly in the Rocky Mountain region where a predominant portion of the Company s reserves are located, experienced a drastic and brief decline at the end of the period ended September 30, 2006. If the spot market prices on September 28, 2006, the market trading date for September 30, 2006 natural gas deliveries, were used the ceiling limitation would have exceeded the Company s net capitalized costs and accordingly no ceiling test write-down would have been indicated. Average wellhead adjusted natural gas and crude oil prices on this date were $3.16 per Mcf and $55.39 per barrel, respectively. When using the spot market prices on September 29, 2006, the last market trading day of the period, the calculation resulted in an indicated $15.5 million pre-tax impairment of the Company s oil and gas properties at September 30, 2006. Average wellhead adjusted natural gas and crude oil spot prices used on this date in the ceiling test calculation were $2.79 per Mcf and $55.39 per barrel, respectively. The Company does not believe this short-term decline in natural gas prices impacts the long-term economic value of its oil and gas properties as its average reserve life is approximately 15 years with individual well lives ranging up to 40 years.

Subsequent to September 30, 2006 natural gas prices both nationwide and in the Rocky Mountain region increased significantly. In accordance with the full cost accounting rules the Company recalculated its full cost "ceiling" using November 2, 2006 average wellhead adjusted spot prices of $5.88 per Mcf and $48.69 per barrel, respectively. These prices resulted in a "ceiling" limit significantly in excess of the Company's net capitalized costs, thereby eliminating the need to take a charge to earnings and write-down the carrying value of the Company's oil and gas properties.

(14) IMPAIRMENT OF LONG-LIVED ASSETS AND CAPITALIZED DEVELOPMENT COSTS

Due to a significant increase in the long-term forecasts for natural gas prices during the third quarter of 2005, the operation of the Company s Las Vegas I gas-fired power plant (Las Vegas I) became uneconomic. Accordingly, the Company assessed the recoverability of the carrying value of Las Vegas I in accordance with the provisions of SFAS No. 144 Accounting for the Impairment of Long-lived Assets (SFAS 144).

Las Vegas I is a 53 megawatt, natural gas-fired, combined-cycle turbine operating under a contract as a qualifying facility as defined by the Public Utility Regulatory Policies Act of 1978. Under the contract, which extends through 2024, the Company sells capacity and energy to Nevada Power Company and accepts price risk associated with the plant s fuel requirements. While the Company s oil and gas exploration and production operation produces gas sufficient to cover the plant s fuel requirements thus providing an internal hedge, SFAS 144 requires the determination of asset impairment at each asset group which has separately identifiable cash flows.

The carrying value of the assets tested for impairment was $60.3 million. The assessment resulted in an impairment charge in September, 2005 of $50.3 million to write down the related Property, plant and equipment by $44.7 million, net of accumulated depreciation of $11.1 million, and intangible assets by $5.6 million, net of accumulated amortization of $1.5 million. 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. This charge is included as a component of Operating expenses on the accompanying Condensed Consolidated Statements of Income. Operating results from Las Vegas I are included in the Power Generation Segment.

In addition, during the three-month period ended September 30, 2005, the Company recorded an $8.9 million pre-tax charge for the write-off and expensing of certain capitalized costs for various energy development projects determined less likely to advance, and costs related to unsuccessfully bid projects during the third quarter of 2005. The Company determined these projects were less likely to advance, due to reduced economic feasibility of gas-fired power generation in the expected sustained high-priced natural gas environment, increased expectations of reliance on renewable or coal-fired generation, and a perceived preference of utilities in certain regions to acquire existing merchant generation at significant discounts as an alternative to entering into contracts for capacity and energy from new generation. These costs had been capitalized as management believed it was probable that such costs would ultimately result in acquisition or construction of the projects. This charge is included as a component of Operating expenses on the accompanying Condensed Consolidated Statements of Income. For segment reporting the development costs are included in Corporate results.

(15) 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, 2006, substantially all of the Company s operations and assets are located within the United States. On March 1, 2006, the Company completed the sale of the operating assets of Black Hills Energy Resources, Inc. and related subsidiaries, the Company s crude oil marketing and pipeline transportation business which for segment reporting was classified in the Energy marketing and transportation segment; and on June 30, 2005 the Company completed the sale of its subsidiary, Black Hills FiberSystems, Inc., which operated as the Company s Communications segment (see Note 19). The financial information of the related crude oil marketing and pipeline transportation business and communications segment has been reclassified into Discontinued operations on the accompanying condensed consolidated financial statements.

The Company conducts its operations through the following six reporting segments: Retail Services group consisting of the following segments: Electric utility, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; and Electric and gas utility, acquired January 21, 2005, which supplies electric and gas utility service to Cheyenne, Wyoming and vicinity; and Wholesale Energy group, consisting of the following segments: Coal mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and gas, which explores for and produces oil and gas primarily in the Rocky Mountain region, with non-operated interests in Texas, California, Oklahoma and other states; Energy marketing, which markets natural gas, crude oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regions; and Power generation, which produces and sells power and capacity to wholesale customers with plants concentrated in Colorado, Nevada, Wyoming and California.

Segment information follows the same accounting policies as described in Note 22 of the Company s 2005 Annual Report on Form 10-K. In accordance with the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71), intercompany fuel sales to the electric utility are not eliminated.

23

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

Three Month Period Ended September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 52,467	$ 723	$ 5,764
Electric and gas utility	24,479		953
Wholesale energy:			
Coal mining	6,055	3,391	1,908
Oil and gas	22,969		3,006
Energy marketing	6,327		2,378
Power generation	42,700		9,839
Corporate	11		(1,649)
Inter-segment eliminations		(1,514)	
Total	$ 155,008	$ 2,600	$ 22,199

Three Month Period Ended September 30, 2005	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Retail services:			
Electric utility	$ 48,336	$ 938	$ 1,888
Electric and gas utility	23,501		(127)
Wholesale energy:			
Coal mining	5,537	2,945	1,643
Oil and gas	22,800	7	5,109
Energy marketing	3,398		(1,206)
Power generation	43,076		(24,587)*
Corporate	93		(6,504)**
Inter-segment eliminations		(1,623)	
Total	$ 146,741	$ 2,267	$ (23,784)

* Loss from continuing operations includes $32.7 million after-tax impairment charge for Las Vegas I.
** Loss from continuing operations includes $5.8 million after-tax for the write-off and expensing of certain capitalized project development costs.

	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Nine Month Period Ended September 30, 2006			
Retail services:			
Electric utility	$ 142,676	$ 1,518	$ 13,099
Electric and gas utility	97,907		3,214
Wholesale energy:			
Coal mining	15,905	9,579	4,091
Oil and gas	69,519		10,439
Energy marketing	34,907		13,249
Power generation	114,991		14,310
Corporate	43		(5,274)
Inter-segment eliminations		(3,733)	
Total	$ 475,948	$ 7,364	$ 53,128

	External Operating Revenues	Inter-segment Operating Revenues	Income (Loss) from Continuing Operations
Nine Month Period Ended September 30, 2005			
Retail services:			
Electric utility	$ 133,295	$ 1,387	$ 9,619
Electric and gas utility	78,034		1,028
Wholesale energy:			
Coal mining	15,717	9,144	4,860
Oil and gas	61,504	7	14,346
Energy marketing	16,193		2,187
Power generation	121,366		(14,601)*
Corporate	647		(10,654)**
Inter-segment eliminations		(3,481)	
Total	$ 426,756	$ 7,057	$ 6,785

* Loss from continuing operations includes $32.7 million after-tax impairment charge for Las Vegas I.

** Loss from continuing operations includes $6.2 million after-tax for the write-off and expensing of certain capitalized project development costs.

Other than the sale of the assets of the crude oil marketing and transportation business and its reclassification to Discontinued operations, and the acquisition of certain oil and gas assets in the Piceance Basin in Colorado, the Company had no material changes in the assets of its reporting segments, as reported in Note 22 of the Notes to Consolidated Financial Statements in the Company s 2005 Annual Report on Form 10-K, beyond changes resulting from normal operating activities.

(16) 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 2005 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 Company s natural gas and crude oil marketing subsidiary, Enserco Energy Inc. (Enserco), recently began marketing crude oil in the Rocky Mountain region out of the Company s Golden, Colorado offices. Our primary strategy involves executing physical crude oil purchase contracts with producers, and reselling into various markets. These transactions are primarily entered into as back-to-back purchases and sales, effectively locking in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. Under FAS 133, mark-to-market accounting for the related commodity contracts in the Company s back-to-back strategy results in an acceleration of marketing margins locked in for the term of the contracts. These are generally short-term contracts with automatic renewals (typically monthly) if there is no notice of cancellation. The realized and unrealized gains and losses from the oil marketing activities are shown net on the accompanying Condensed Consolidated Income Statement within Operating revenues .

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, 2006		Outstanding at December 31, 2005		Outstanding at September 30, 2005	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of MMbtus)						
Natural gas basis swaps purchased	146,331	16	43,507	22	51,155	18
Natural gas basis swaps sold	153,530	18	53,665	22	60,522	18
Natural gas fixed - for - float swaps purchased	44,600	18	17,083	23	19,979	26
Natural gas fixed - for - float swaps sold	58,248	6	24,871	23	29,576	26
Natural gas physical purchases	66,972	27	59,855	34	62,020	37
Natural gas physical sales	117,135	39	88,302	46	110,341	49
Natural gas options purchased	18,447	15	6,176	21	12,725	24
Natural gas options sold	18,447	15	6,176	21	12,725	24

	Outstanding at September 30, 2006		Outstanding at December 31, 2005		Outstanding at September 30, 2005	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
(in thousands of barrels)						
Crude oil physical purchases	404	1				
Crude oil physical sales	404	1				
(Dollars, in thousands)						
Canadian dollars purchased	$ 23,000	1	$ 88,000	2	$ 29,700	1
Canadian dollars sold	$ 1,000	2	$ 29,000	5	$ 37,600	8

Derivatives and certain natural gas and crude oil marketing activities were marked to fair value on September 30, 2006, December 31, 2005 and September 30, 2005, 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	Unrealized Gain (Loss)
September 30, 2006	$ 51,528	$ 1,629	$ 17,546	$ 1,873	$ 33,738
December 31, 2005	$ 20,326	$ 1,747	$ 20,751	$ 2,086	$ (764)
September 30, 2005	$ 33,112	$ 4,722	$ 97,215	$ 4,541	$ (63,922)

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a fair value hedge transaction. These volumes are stated at market value using published spot 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, 2006, December 31, 2005 and September 30, 2005, the market adjustments recorded in inventory were $(29.8) million, $6.6 million and $61.0 million, respectively.

Activities Other Than Trading

Oil and Gas Exploration and Production

On September 30, 2006, December 31, 2005 and September 30, 2005, 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, 2006								
Crude oil swaps/options	300,000	1.00	$ 456	$	$ 1,308	$ 282	$ (1,441)	$ 307
Natural gas swaps	6,765,000	1.50	13,231	1,116			14,347	
			$ 13,687	$ 1,116	$ 1,308	$ 282	$ 12,906	$ 307
December 31, 2005								
Crude oil swaps/options	300,000	1.00	$ 150	$	$ 2,535	$ 307	$ (2,842)	$ 150
Natural gas swaps	2,950,000	0.60		151	2,560		(2,409)	
			$ 150	$ 151	$ 5,095	$ 307	$ (5,251)	$ 150
September 30, 2005								
Crude oil swaps	300,000	1.00	$	$	$ 4,448	$ 1,177	$ (5,607)	$ (18)
Natural gas swaps	2,502,500	0.50			11,829	378	(12,207)	
			$	$	$ 16,277	$ 1,555	$ (17,814)	$ (18)

*crude in barrels, gas in MMbtu s

Based on September 30, 2006 market prices, an $11.6 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 losses will likely change during the next twelve months as market prices change.

Fuel in Storage

The Company holds natural gas in storage for use as fuel for generating electricity with certain of its gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, the Company utilizes various derivative instruments in managing these risks.

On September 30, 2006, December 31, 2005 and September 30, 2005, the Company had the following swaps 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 (Loss)	Unrealized Gain (Loss)
September 30, 2006								
Natural gas swaps	525,000	0.5	$ 1,634	$	$	$	$ 410	$ 1,224
December 31, 2005								
Natural gas swaps	275,000	0.25	$ 192	$	$ 219	$	$ (219)	$ 192
September 30, 2005								
Natural gas swaps	425,000	0.50	$	$	$ 1,246	$	$ (759)	$ (487)

*gas in MMbtu s

Based on September 30, 2006 market prices, a gain of $0.4 million would be realized and reported in pre-tax earnings during the next twelve months related to the cash flow hedge. Estimated and actual realized gains will likely change during the next twelve months as market prices change.

In addition, certain volumes of natural gas inventory were designated as the underlying hedged item in fair value hedge transactions. These volumes are stated at market value using published spot industry quotations. Market adjustments are recorded in inventory on the Balance Sheet and the related unrealized gain/loss on the Statement of Income. As of September 30, 2006, December 31, 2005 and September 30, 2005, the market adjustments recorded in inventory were $(1.2) million, $(0.2) million and $0.5 million, respectively.

Financing Activities

On September 30, 2006, December 31, 2005 and September 30, 2005, 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 Income (Loss)	Pre-tax Income (Loss)
September 30, 2006									
Interest rate swaps	$ 100,000	5.09%	10.00	$ 141	$ 452	$ 83	$ 758	$ (248)	$
December 31, 2005									
Interest rate swaps	$ 163,000	4.43%	10.00	$ 13	$	$ 76	$ 230	$ (249)	$ (44)
September 30, 2005									
Interest rate swaps	$ 113,000	4.22%	1.00	$ 72	$	$ 203	$	$ 9	$ (140)

Based on September 30, 2006 market interest rates and balances, a gain of less than $0.1 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized amounts will likely change during the next twelve months as market interest rates change.

(17) LEGAL PROCEEDINGS

The Company is subject to various legal proceedings, claims and litigation as described in Note 20 of the Notes to Consolidated Financial Statements in the Company s 2005 Annual Report on Form 10-K.

Forest Fire Claims

As disclosed in previous filings with the SEC, the Company s subsidiary Black Hills Power, Inc. (Black Hills Power) settled governmental claims related to the Grizzly Gulch Fire and the Hell Canyon Fire. On August 25, 2006, the U.S. District Court approved a full and final settlement of all governmental claims relating to both fires. The settlement agreements provided for the release and dismissal of all claims against Black Hills Power. For its part, Black Hills Power did not admit liability for the fires, but agreed to make settlement payments for the Grizzly Gulch Fire as follows: (1) Payment of $2.3 million dollars to the State of South Dakota; (2) Payment of $1 million dollars to the State s Special Emergency Disaster Revenue Fund and (3) Payment of $3.6 million dollars to the United States Government. Black Hills Power agreed to a settlement payment for the Hell Canyon Fire of $1 million dollars, which was divided between the state and federal governments. The settlements did not have a material adverse effect on the Company s financial condition or results of operations.

While the governmental case was pending, a number of private claims for damages arising out of the Grizzly Gulch Fire were filed in Lawrence County Circuit Court, South Dakota. Counsel for these litigants had agreed to a stay of the proceedings pending the resolution of governmental claims. As a result of the settlement of the governmental cases, the private claims will now proceed through discovery. No trial date or other scheduling order has been set for these matters. The Company will continue to defend these matters. While the outcome of the remaining private suits is uncertain, it is not expected to have a material impact upon the Company s financial condition or results of operations.

Earn-Out Litigation

As disclosed in previous filings with the SEC, on August 13, 2004, Gerald R. Forsythe and other individuals identified as Stockholders under an Agreement and Plan of Merger dated July 7, 2000, commenced litigation against Black Hills Corporation in United States District Court, Northeastern District of Illinois, Eastern Division (the Litigation). The Litigation concerns the Company s performance of its obligations under the Earn-Out provisions of the Agreement and Plan of Merger. Under these provisions, the Stockholders, who are former owners of Indeck Capital, Inc., were entitled to receive contingent merger consideration for a period of four years following the merger of the Company s wholly-owned subsidiary, Indeck Capital with Black Hills Energy Capital, Inc. (BHEC). The contingent merger consideration was not to exceed $35.0 million and was based on the acquired companies earnings over the four year period beginning in 2000. As of September 30, 2006, $11.3 million has been either paid or offered for payment under the Earn-Out provisions.

The Stockholders allege that the Company failed to meet its obligation to produce documentation for its calculation of the contingent merger consideration, and in addition, failed to issue stock compensation in the full amount due to them. The Company denies these allegations and contends that it has fully and in good faith performed all of its obligations under the Agreement and Plan of Merger.

In addition, the Company contended that the Agreement and Plan of Merger provides for mandatory arbitration as a medium for resolution of all disputes relating to the payment of contingent merger consideration. The Company filed a Motion to Dismiss or Stay the Litigation, along with an order compelling the Stockholders to pursue their claims in arbitration. On July 7, 2005, the U.S. District Court entered its order compelling arbitration of two issues relating to the Earn Out calculation, but held that two other issues (inter-company interest allocations and capitalization of BHEC) would remain subject to determination through the Litigation. The court declined to stay the Litigation on those two issues and consequently, this dispute will be resolved in parallel proceedings. No trial date has been set.

On October 6, 2006, the Court granted Plaintiffs Motion to Amend the Complaint in the Litigation to add new claims, and re-characterize others. Under the Amended Complaint, a count for breach of contract was withdrawn and replaced by similar allegations under a theory of breach of the covenant of good faith and fair dealing. The first new count seeks damages for alleged destruction or spoliation of corporate records relating to the Earn-Out process and obligation. The second claim asserts damages for alleged fraud, and seeks recovery against current and former officers of the Company, as well as the Company itself. The fraud theory alleges that debt represented by inter-company loan transactions was non-existent or illegal, and representations by the Company to the contrary were fraudulent. Under the fraud claim, the Plaintiffs assert a similar claim for compensatory damages and add a new claim for exemplary damages. The Company hired separate counsel for the individual defendants and will file a motion to dismiss the Amended Complaint.

The parties retained an arbitrator who will direct the process and decide the issues in arbitration, according to the procedure stated in the Merger Agreement. No process or time schedule for the arbitration has been established.

The outcome of this matter is uncertain, as is the amount of contingent merger consideration that could be awarded following arbitration and/or litigation. If any additional merger consideration is awarded, it would be recorded as additional goodwill. If an adverse outcome was to occur and punitive damages were awarded, the punitive damages would be recorded as an expense.

California Price Reporting and Anti-Trust Litigation

On August 17, 2006, the Company s subsidiary, Enserco Energy Inc., was served as an additional defendant in sixteen lawsuits pending in San Diego Superior Court, in the State of California, JCCP Nos. 4221, 4224, 4226, and 4228. The Plaintiffs are purported natural gas customers who initially filed separate lawsuits in various California superior courts. These lawsuits have been coordinated in the San Diego Superior Court with numerous other natural gas actions under the heading, In re Natural Gas Anti-Trust Cases I, II, III, IV, and V. The lawsuits have been pending against other marketers, traders, transporters and sellers of natural gas since as early as 2004. Plaintiffs allege that beginning at least by the summer of 2000, defendants, including Enserco, used various practices to manipulate natural gas prices in California in violation of the Cartwright Act and other California state laws. The Plaintiffs assert certain wrongful conduct on the part of other defendants which is not asserted against Enserco. They allege manipulation of prices by Enserco through reporting of transactions to industry trade publications. No specific amount of damages is alleged. Enserco intends to vigorously defend the lawsuits, but is unable to predict the timing or outcome of these actions, including the possible amount of an adverse result, if that should occur.

PPM Energy, Inc. Demand for Arbitration

As disclosed in previous filings with the SEC, the Company s subsidiary, Black Hills Power received a Demand for Arbitration from PPM Energy, Inc. (PPM) on January 2, 2004, that alleged claims for breach of contract and requested a declaration of the parties rights and responsibilities under an Exchange Agreement executed in April of 2001. PPM asserted the Exchange Agreement obligated Black Hills Power to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM requested an award of damages in an amount not less than $20.0 million. Black Hills Power filed its Response to Demand, including a counterclaim that sought recovery of sums PPM had refused to pay pursuant to the Exchange Agreement. The dispute was presented to the arbitrator in August 2005 and the arbitrator delivered his decision on June 5, 2006.

The arbitrator concluded both parties failed to perform the Exchange Agreement, in certain respects. Black Hills Power has paid PPM a net settlement of $1.1 million in accordance with the decision. The Company does not believe that the decision will have a material impact on its ability to market surplus power in the future.

Price Reporting Class Actions

As disclosed in Note 20 of the Notes to Consolidated Financial Statements in the Company s 2005 Annual Report on Form 10-K, the Company reached a tentative settlement with the Plaintiffs on October 28, 2005. Approval of the final settlement documents occurred on May 19, 2006 and the litigation is now concluded.

Except as described above, 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 2006.

(18) ACQUISITIONS

Oil and Gas Assets

On March 17, 2006, the Company acquired certain oil and gas assets of Koch Exploration Company, LLC, for approximately $51.4 million. The associated acreage position is located in the Piceance Basin in Colorado and includes approximately 40 Bcfe of proved reserves, including approximately 31 Bcfe of proved undeveloped reserves, which are substantially all gas. The acquisition includes 63 producing wells and majority interests in associated midstream and gathering assets.

In addition, on August 30, 2006, the Company acquired from a third party most of the remaining working interests associated with the property acquired in March 2006 from Koch Exploration Company. The acquisition includes approximately 22.4 Bcfe of proven reserves, of which 17.9 Bcfe are proved undeveloped reserves. As part of the transaction, the Company also acquired rights to more than 15,000 net acres of undeveloped leasehold adjacent or near existing operations in the Piceance Basin of Colorado. The purchase price for the transaction is approximately $24.0 million. With completion of the acquisition, the Company s leasehold position in the Piceance Basin totals approximately

75,000 net acres.

Cash payments for these acquisitions were funded with a combination of operating cash flows and short-term borrowings. Operations of these assets prior to acquisition were not material to the Company s consolidated operations; therefore no pro-forma information has been presented herein.

Cheyenne Light, Fuel and Power

On January 21, 2005, the Company completed the acquisition of Cheyenne Light, Fuel and Power (Cheyenne Light). The Company purchased all the common stock of Cheyenne Light, including the assumption of outstanding debt of approximately $24.6 million, for approximately $90.7 million.

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 estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. The results of operations of Cheyenne Light have been included in the accompanying Condensed Consolidated Financial Statements since the acquisition date.

The following pro-forma consolidated results of operations for the Company have been prepared as if the Cheyenne Light acquisition had occurred on January 1, 2005 (in thousands):

	Nine Month Period Ended September 30, 2005	
Operating revenues	$	442,991
Income from continuing operations		6,964
Net income		6,986
Earnings per share		
Basic:		
Continuing operations	$	0.21
Total	$	0.21
Diluted:		
Continuing operations	$	0.21
Total	$	0.21

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.

(19) DISCONTINUED OPERATIONS

The Company accounts for its discontinued operations under the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS 144). Accordingly, results of operations and the related charges for discontinued operations have been classified as Income (loss) 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 Crude Oil Marketing and Transportation Assets

On March 1, 2006, the Company sold the operating assets of Black Hills Energy Resources, Inc. and related subsidiaries, its crude oil marketing and transportation business for approximately $41 million. Assets sold include the 200-mile Millennium and the 190-mile Kilgore Pipelines, oil marketing contracts and certain other ancillary assets. Following the sale, the Company closed the operations of the Houston, Texas based business. For business segment reporting purposes, Black Hills Energy Resources was included in the Energy marketing and transportation segment.

Revenues and net (loss) income from the discontinued operations were as follows (in thousands):

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Operating revenues	$ 6	$ 224,003	$ 171,911	$ 544,660
Pre-tax (loss) income from discontinued operations (including 2006 severance payments)	$ (164)	$ 80	$ (2,930)	$ 3,427
Pre-tax gain on sale of assets	7		13,659	
Income tax benefit (expense)	74	54	(3,833)	(1,070)
Net (loss) income from discontinued operations	$ (83)	$ 134	$ 6,896	$ 2,357

Losses incurred subsequent to the asset sale resulted from the settlement of certain contract disputes with the purchaser and other costs incurred in closing down the business operations.

Assets and liabilities of the Crude oil marketing and transportation business were as follows (in thousands):

	September 30, 2006	December 31, 2005	September 30, 2005
Current assets	$ 1,041	$ 94,697	$ 91,681
Property, plant and equipment, net		25,364	25,217
Other non-current assets	2	2,097	2,121
Current liabilities	(3,250)	(89,750)	(83,671)
Other non-current liabilities	(881)	(3,068)	(3,049)
Net (deficit) assets	$ (3,088)	$ 29,340	$ 32,299

Communications Segment

On June 30, 2005, the Company completed the sale of its Communications business, Black Hills FiberSystems, Inc. to Prairie*Wave* Communications, Inc. Under the purchase and sale agreement, the Company received a cash payment of approximately $103 million.

Revenues and net income (loss) from the discontinued operations were as follows (in thousands):

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Operating revenues	$	$	$	$ 21,877
Pre - tax income from discontinued operations	$	$	$	$ 3,978
Pre-tax loss on disposal		(255)		(7,490)
Income tax benefit (expense)	164	(14)	164	1,396
Net income (loss) from discontinued operations	$ 164	$ (269)	$ 164	$ (2,116)

Sale of Pepperell Plant

On April 8, 2005, the Company sold the 40 megawatt gas-fired Pepperell plant to an unrelated party for a nominal amount plus the assumption of certain obligations. For business segment reporting purposes, the Pepperell plant results were previously included in the Power generation segment. Financial results of these discontinued operations were not significant to the three and nine month periods ended September 30, 2005.

36

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 retail services and wholesale energy. We report our business groups in the following segments:

Business Group	**Financial Segment**
Retail services group	Electric utility Electric and gas utility
Wholesale energy group	Energy marketing Power generation Oil and gas Coal mining

Our retail services group consists of our electric and gas utilities segments. Our electric utility generates, transmits and distributes electricity to an average of approximately 63,500 customers in South Dakota, Wyoming and Montana. Our electric and gas utility, acquired on January 21, 2005, serves approximately 38,700 electric and 32,500 natural gas customers in Cheyenne, Wyoming and vicinity. Our wholesale energy group engages in the production of electric power through ownership of a diversified portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; and the marketing of fuel products.

In March 2006, we sold the operating assets of Black Hills Energy Resources, Inc. and related subsidiaries, our crude oil marketing and pipeline transportation business headquartered in Houston, Texas. These activities were previously reported in our Energy marketing and transportation segment. In June 2005, we sold our subsidiary, Black Hills FiberSystems, Inc., previously reported as our Communications segment. In April 2005, we also sold our Pepperell power plant, our last remaining power plant in the eastern region, which was previously reported in our Power generation segment. Prior period results have been reclassified to present the financial information as Discontinued operations.

The Company s oil and gas segment follows the full cost method of accounting for its oil and gas properties. Under the full cost method, costs related to acquisition, exploration and development drilling activities are capitalized. The net capitalized costs are subject to a ceiling test that limits these costs to the estimated present value of future net revenues from proved reserves based on a single day s spot market prices, and the lower of cost or fair value of unproved properties. Rules mandated by the Securities and Exchange Commission require that future net revenues be based on end-of-period spot market prices, with consideration for alternate prices only to the extent provided for by contractual arrangements, and discounted at a 10 percent interest rate. If the net capitalized costs exceed the full cost ceiling at period end, a permanent non-cash write-down would be required to be charged to earnings in that period unless subsequent market price changes eliminate or reduce the indicated write-down.

In accordance with the Company s full cost method of accounting for its oil and gas properties, we conducted our quarterly ceiling test as of September 30, 2006. Spot market prices for natural gas, particularly in the Rocky Mountain region where a predominant portion of the Company s reserves are located, experienced a drastic and brief decline at the end of the period ended September 30, 2006. If the spot market prices on September 28, 2006, the market trading date for September 30, 2006 natural gas deliveries, were used the ceiling limitation would have exceeded the Company s net capitalized costs and accordingly no ceiling test write-down would have been indicated. Average wellhead adjusted natural gas and crude oil prices on this date were $3.16 per Mcf and $55.39 per barrel, respectively. When using the spot market prices on September 29, 2006, the last market trading day of the period, the calculation resulted in an indicated $15.5 million pre-tax impairment of the Company s oil and gas properties at September 30, 2006. Average wellhead adjusted natural gas and crude oil spot prices used on this date in the ceiling test calculation were $2.79 per Mcf and $55.39 per barrel, respectively. The Company does not believe this short-term decline in natural gas prices impacts the long-term economic value of its oil and gas properties as its average reserve life is approximately 15 years with individual well lives ranging up to 40 years.

Subsequent to September 30, 2006 natural gas prices both nationwide and in the Rocky Mountain region increased significantly. In accordance with the full cost accounting rules the Company recalculated its full cost "ceiling" using November 2, 2006 average wellhead adjusted spot prices of $5.88 per Mcf and $48.69 per barrel, respectively. These prices resulted in a "ceiling" limit significantly in excess of the Company's net capitalized costs, thereby eliminating the need to write-down the carrying value of the Company's oil and gas properties.

The following discussion should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations included in our 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Results of Operations

Consolidated Results

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

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Revenues				
Retail services	$ 76,946	$ 71,837	$ 240,583	$ 211,329
Wholesale energy	80,651	77,078	242,686	221,837
Corporate	11	93	43	647
	$ 157,608	$ 149,008	$ 483,312	$ 433,813
Income/(Loss) from Continuing Operations				
Retail services	$ 6,717	$ 1,761	$ 16,313	$ 10,647
Wholesale energy	17,131	(19,041)	42,089	6,792
Corporate	(1,649)	(6,504)	(5,274)	(10,654)
	$ 22,199	$ (23,784)	$ 53,128	$ 6,785

Discontinued operations in 2006 and 2005 represent the operations of our crude oil marketing and transportation business, sold in March 2006; our Communications segment, Black Hills FiberSystems, Inc., which was sold in June 2005; and our 40 megawatt Pepperell power plant, which was sold in April 2005.

Prior to the reclassification of the financial results of our crude oil marketing and transportation business into discontinued operations, the related revenues and cost of sales were presented on a gross basis. Accordingly, our operating revenues and expenses, as previously presented in the 2005 interim financial statements, are adjusted by the following to reflect crude oil marketing and transportation revenues and cost of sales in discontinued operations (in millions):

	Three month periods ended				Total
	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005	2005
Operating revenues	$ 153.6	$ 167.1	$ 224.0	$ 233.4	$ 778.1
Cost of sales	$ 149.3	$ 163.9	$ 221.6	$ 230.4	$ 765.2

On January 21, 2005, we completed the acquisition of Cheyenne Light, Fuel and Power Company (Cheyenne Light), an electric and natural gas utility serving customers in Cheyenne, Wyoming and vicinity. The results of operations of Cheyenne Light have been included in the accompanying Condensed Consolidated Financial Statements from the date of acquisition.

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005. Revenues for the three months ended September 30, 2006 increased 6 percent, or $8.6 million, compared to the same period in 2005. Increased revenues were primarily driven by higher retail and wholesale sales at Black Hills Power, higher rates at Cheyenne Light and higher margins in our energy marketing activities.

Operating expenses decreased 35 percent, or $62.9 million, primarily due to the 2005 impairment charge of $50.3 million of the Las Vegas I power plant, the 2005 write-off and expensing of $8.9 million of certain capitalized development costs and, in 2006, lower legal costs and receipt of $3.0 million of insurance proceeds for the Las Vegas II power plant, which was presented as a $3.0 million reduction to operating expenses.

Income from continuing operations increased $46.0 million due primarily to the following:

a $3.9 million increase in Electric utility earnings;

a $1.1 million increase in Electric and gas utility earnings;

a $3.6 million increase in Energy marketing earnings;

a $34.4 million increase in Power generation earnings, which includes the $32.7 million after-tax impairment charge at LV I in September 2005; and

- a $4.9 million decrease in unallocated corporate costs,

partially offset by:

- a $2.1 million decrease in Oil and gas earnings.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005. Revenues for the nine months ended September 30, 2006 increased 11 percent, or $49.5 million, compared to the same period in 2005. Increased revenues were primarily driven by higher retail and wholesale sales at Black Hills Power, a full nine months of activity and higher rates at Cheyenne Light, higher margins in our energy marketing activities and higher revenues from oil and gas production, partially offset by lower revenues at our power generation and coal mining businesses due to scheduled and unscheduled plant outages.

Operating expenses decreased 7 percent, or $27.4 million, primarily due to the 2005 impairment charge of $50.3 million of the Las Vegas I power plant, the 2005 write-off and expensing of certain capitalized development costs and, in 2006, lower legal costs and receipt of insurance proceeds for the Las Vegas II power plant, which was presented as a $3.9 million reduction to operating expenses, partially offset by higher fuel and purchase power costs, repairs and maintenance for scheduled and unscheduled plant outages, increased compensation costs and provision for bad debt.

Income from continuing operations increased $46.3 million due primarily to the following:

- a $3.5 million increase in Electric utility earnings;
- a $2.2 million increase in Electric and gas utility earnings;
- an $11.1 million increase in Energy marketing earnings;
- a $28.9 million increase in Power generation earnings, which includes the $32.7 million after-tax impairment charge at Las Vegas I in September 2005; and
- a $5.4 million decrease in unallocated corporate costs,

partially offset by the following decreases:

- a $3.9 million decrease in Oil and gas earnings; and
- a $0.8 million decrease in Coal mining earnings.

See the following discussion of our business segments under the captions Retail Services Group and Wholesale Energy Group for more detail on our results of operations.

The following business group and segment information does not include intercompany eliminations or discontinued operations. Accordingly, 2005 information has been revised as necessary to reclassify information related to operations that were discontinued.

Retail Services Group

Electric Utility

	Three Months Ended September 30, 2006 (in thousands)	2005	Nine Months Ended September 30, 2006	2005
Revenue	$ 53,190	$ 49,274	$ 144,194	$ 134,682
Operating expenses	40,423	43,811	114,839	111,603
Operating income	$ 12,767	$ 5,463	$ 29,355	$ 23,079
Income from continuing operations and net income	$ 5,764	$ 1,888	$ 13,099	$ 9,619

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

	Electric Revenue (in thousands)					
	Three Months Ended September 30,			Nine Months Ended September 30,		
Customer Base	2006	Percentage Change	2005	2006	Percentage Change	2005
Commercial	$ 14,499	3%	$ 14,127	$ 37,766	2%	$ 37,179
Residential	10,886	4	10,441	30,465	3	29,662
Industrial	5,249	3	5,111	15,448	4	14,874
Municipal sales	731	5	693	1,842	6	1,740
Total retail sales	31,365	3	30,372	85,521	2	83,455
Contract wholesale	6,423	12	5,719	18,451	6	17,377
Wholesale off - system	12,607	7	11,766	31,416	8	29,050
Total electric sales	50,395	5	47,857	135,388	4	129,882
Other revenue	2,795	97	1,417	8,806	83	4,800
Total revenue	$ 53,190	8%	$ 49,274	$ 144,194	7%	$ 134,682

	Megawatt Hours Sold					
	Three Months Ended September 30,			Nine Months Ended September 30,		
Customer Base	2006	Percentage Change	2005	2006	Percentage Change	2005
Commercial	191,460	2%	188,481	508,099	2%	498,643
Residential	127,100	4	122,400	374,378	3	363,039
Industrial	110,873	2	108,445	322,233	4	310,538
Municipal sales	10,365	8	9,622	25,076	9	22,912
Total retail sales	439,798	3	428,948	1,229,786	3	1,195,132
Contract wholesale	165,024	13	145,993	481,969	5	457,990
Wholesale off-system	271,445	37	198,031	719,782	20	598,105
Total electric sales	876,267	13%	772,972	2,431,537	8%	2,251,227

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Regulated power plant fleet availability:				
Coal-fired plants	97.5%	85.8%	91.8%	90.2%
Other plants	99.8%	99.4%	99.6%	99.4%
Total availability	98.5%	91.7%	95.2%	94.2%

	Three Months Ended September 30,			Nine Months Ended September 30,		
Resources	2006	Percentage Change	2005	2006	Percentage Change	2005
Megawatt-hours generated:						
Coal	445,984	12%	397,513	1,266,938	1%	1,259,822
Gas	26,756	21	22,065	40,449	47	27,545
	472,740	13	419,578	1,307,387	2	1,287,367
Megawatt-hours purchased	424,209	12	378,986	1,200,715	16	1,032,091
Total resources	896,949	12%	798,564	2,508,102	8%	2,319,458

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Heating and cooling degree days:				
Actual				
Heating degree days	250	120	3,906	4,043
Cooling degree days	714	673	925	821
Percent of normal				
Heating degree days	110%	53%	86%	89%
Cooling degree days	145%	136%	155%	138%

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005. Income from continuing operations increased $3.9 million primarily due to increased revenues and lower purchased power costs and operations and maintenance expense, partially offset by a $0.9 million negative impact to income tax expense related to the resolution of federal income tax audits.

Electric utility revenues increased 8 percent for the three month period ended September 30, 2006, compared to the same period in the prior year. Total retail megawatt-hour sales increased 3 percent compared to the three months ended September 30, 2005. Heating degree days, which is a measure of weather trends, were 108 percent higher and cooling degree days were 6 percent higher, than the same period in the prior year. Wholesale off-system sales increased 7 percent due to a 37 percent increase in megawatt-hours sold partially offset by a 22 percent decrease in average price received. Megawatt-hours available for wholesale off-system sales increased over the prior period due to the unscheduled Neil Simpson II plant outage in July and August of 2005.

Electric operating expenses decreased 8 percent for the three month period ended September 30, 2006, compared to the same period in the prior year. Fuel and purchased power costs decreased 2 percent due to a 4 percent decrease in purchased power at average prices that were 14 percent lower than the previous period, partially offset by increased fuel production costs. In addition, 2005 purchase power costs included approximately $2.8 million to cover the Neil Simpson II unscheduled plant outage in July and August of 2005. Megawatt hours generated and purchased increased 13 percent and 12 percent, respectively, for the three months ended September 30, 2006 compared to the same period in 2005. Operating expense for the three months ended September 30, 2006 was also affected by lower corporate allocations and a decrease in power marketing legal costs relative to costs incurred in the third quarter of 2005 (See Notes to Condensed Consolidated Financial Statements, Note 17 Legal Proceedings, for discussion of power marketing legal settlement).

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005. Income from continuing operations increased 36 percent primarily due to increased revenues partially offset by increased fuel and purchased power costs, operations and maintenance expense and a $0.9 million negative impact to income tax expense related to the resolution of federal income tax audits.

Electric utility revenues increased 7 percent for the nine month period ended September 30, 2006, compared to the same period in the prior year. Total retail megawatt-hour sales increased 3 percent compared to the nine months ended September 30, 2005. Heating degree days, which is a measure of weather trends, were 3 percent lower and cooling degree days were 13 percent higher, than the same period in the prior year. Wholesale off-system sales increased 8 percent due to a 20 percent increase in megawatt-hours sold partially offset by a 10 percent decrease in average price received.

43

Electric operating expenses increased 3 percent for the nine month period ended September 30, 2006, compared to the same period in the prior year. Fuel and purchased power costs increased 10 percent due to an 8 percent increase in megawatt-hours sold. Megawatt hours generated increased 2 percent at a higher average price and megawatt hours purchased increased 16 percent at a 7 percent decrease in average price. We utilized higher cost gas generation in 2006 to cover scheduled and unscheduled outages at the Wyodak plant. In addition, 2005 purchased power costs include approximately $2.8 million to cover the Neil Simpson II unscheduled plant outage in July and August of 2005. Operating expense for the nine months ended September 30, 2006 was also affected by increased repairs and maintenance expense incurred for the Wyodak Plant maintenance and higher corporate allocations, partially offset by a decrease in power marketing legal costs relative to costs incurred in 2005 (See Notes to Condensed Consolidated Financial Statements, Note 17 Legal Proceedings, for discussion of power marketing legal settlement).

Request for Rate Increase. On June 30, 2006 our electric utility filed an application with the South Dakota Public Utilities Commission (SDPUC) for an electric rate increase to be effective January 1, 2007. The application requests a 9.5 percent rate increase for all customer classes. In addition, the application proposes annual energy cost adjustments. The proposed cost adjustments would require the electric utility to absorb a portion of power cost increases, depending in part on earnings on certain short-term wholesale sales of electricity. The current rate structure, in place since 1995, does not contain fuel or purchased power adjustment clauses and only provides the ability to request rate relief from energy costs in certain defined situations. We expect these increases, if approved by the SDPUC, would result in an annual revenue increase of approximately $9.5 million. South Dakota retail customers account for approximately 90 percent of the electric utility s total retail revenues. A rate freeze has been in place for the electric utility since 1995.

Electric and Gas Utility

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	January 21, 2005 to September 30, 2005
	(in thousands)			
Revenue	$ 24,479	$ 23,501	$ 97,907	$ 78,034
Purchased gas and electricity	18,409	19,129	78,011	64,073
Gross margin	6,070	4,372	19,896	13,961
Operating expenses	5,047	4,411	15,967	12,169
Operating income	$ 1,023	$ (39)	$ 3,929	$ 1,792
Income (loss) from continuing operations and net income (loss)	$ 953	$ (127)	$ 3,214	$ 1,028

44

The following tables provide certain operating statistics for the Electric and gas utility segment:

Electric Revenue
(in thousands)

Customer Base	Three Months Ended September 30, 2006	Percentage Change	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Percentage Change	January 21, 2005 to September 30, 2005
Commercial	$ 11,979	9%	$ 11,007	$ 33,293	13%	$ 29,568
Residential	6,676	3	6,462	20,666	14	18,052
Industrial	2,036	(10)	2,268	6,361	(5)	6,673
Municipal sales	208	28	163	611	41	432
Total electric sales	20,899	5	19,900	60,931	11	54,725
Other revenue	104		17	330		22
Total revenue	$ 21,003	5%	$ 19,917	$ 61,261	12%	$ 54,747

Resources	Three Months Ended September 30, 2006	Percentage Change	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Percentage Change	January 21, 2005 to September 30, 2005
Megawatt-hours purchased	245,047	(4)%	254,349	732,783	9%	674,921

Gas Revenue
(in thousands)

Customer Base	Three Months Ended September 30, 2006	Percentage Change	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Percentage Change	January 21, 2005 to September 30, 2005
Commercial	$ 805	15%	$ 702	$ 10,776	59%	$ 6,785
Residential	1,997	12	1,784	20,541	63	12,639
Industrial	489	(49)	966	4,665	40	3,336
Total gas sales	3,291	(5)	3,452	35,982	58	22,760
Other sales	185	40	132	664	26	527
Total revenue	$ 3,476	(3)%	$ 3,584	$ 36,646	57%	$ 23,287

Resources	Three Months Ended September 30, 2006	Percentage Change	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Percentage Change	January 21, 2005 to September 30, 2005

Dekatherms purchased	397,997	13%	353,077	2,905,488	19%	2,445,313

45

	Three Months Ended September 30, 2006	Percentage Change	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Percentage Change	January 21, 2005 to September 30, 2005
Electric sales-MWh	234,104		233,737	685,726	5%	650,976
Gas sales-Dth	374,994	(10)%	414,977	3,069,315	10%	2,788,711

	Three Months Ended September 30		Nine Months Ended September 30,	January 21, 2005 to September 30,
	2006	2005	2006	2005
Heating and cooling degree days:				
Actual				
Heating degree days	369	183	4,237	4,190
Cooling degree days	362	376	486	441
Percent of normal				
Heating degree days	113%	56%	90%	89%
Cooling degree days	157%	163%	178%	162%

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005. Income from continuing operations increased $1.1 million for the three months ended September 30, 2006 compared to the three months ended September 30, 2005.

Gross margin increased 39 percent primarily due to an increase in base rates that went into effect January 1, 2006. Heating degree days were 102 percent higher, and cooling degree days were 4 percent lower, than the same period in the prior year. We consider gross margin to be the most useful performance measure as fluctuations in cost of gas and electricity flow through to revenues through cost recovery adjustments.

Operating expenses increased 14 percent primarily due to increased depreciation expense and the write-off of uncollectible accounts.

Nine Months Ended September 30, 2006 Compared to the Period January 21, 2005 to September 30, 2005. Income from continuing operations increased $2.2 million for the nine months ended September 30, 2006 compared to the period January 21 to September 30, 2005.

Gross margin increased 43 percent primarily due to an increase in base rates that went into effect January 1, 2006 and a 10 percent increase in gas usage. Heating degree days were 1 percent higher, and cooling degree days were 10 percent higher, than the same period in the prior year. We consider gross margin to be the most useful performance measure as fluctuations in cost of gas and electricity flow through to revenues through cost recovery adjustments.

Operating expenses increased 31 percent primarily due to increased, depreciation expense, the write-off of uncollectible accounts and increased operating costs due to a full nine months of operations in 2006.

We are progressing with the construction of Wygen II, a 90 megawatt, coal-fired power plant sited at our Wyodak energy complex near Gillette, Wyoming. The power plant is expected to be in commercial operation by the end of 2007. We expect to submit a rate filing in early 2007 with the Wyoming Public Service Commission to include Wygen II in the rate base of Cheyenne Light in order to recover capital and provide a return on invested capital.

Wholesale Energy Group

A discussion of results from our Wholesale Energy group s operating segments follows:

Energy Marketing

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(in thousands)			
Revenue	$ 6,327	$ 3,398	$ 34,907	$ 16,193
Operating expenses	5,923	5,498	17,970	12,914
Operating income (loss)	$ 404	$ (2,100)	$ 16,937	$ 3,279
Income (loss) from continuing operations	$ 2,378	$ (1,206)	$ 13,249	$ 2,187

The following is a summary of average daily energy marketing volumes:

		Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Natural gas physical sales	MMbtus	1,720,800	1,562,200	1,502,000	1,495,000
Crude oil physical barrels	barrels[(a)]	9,200		9,100	

[(a)] Daily oil volumes are calculated as of May 1, 2006 to reflect the start of crude oil marketing by Enserco out of our Golden, Colorado offices.

During May 2006, our natural gas marketing subsidiary, Enserco Energy Inc., began marketing crude oil in the Rocky Mountain region out of our Golden, Colorado offices. Our primary strategy involves executing physical crude oil purchase contracts with producers, and reselling into various markets. These transactions are primarily entered into as back-to-back purchases and sales, effectively locking in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. Under FAS 133, mark-to-market accounting for the related commodity contracts in our back-to-back strategy results in an acceleration of marketing margins locked in for the term of the contracts. These are generally short-term contracts with automatic renewals if there is no notice of cancellation. The realized and unrealized gains and losses from the oil marketing activities are shown net within Operating revenues on the Condensed Consolidated Statement of Income.

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005. Income from continuing operations increased $3.6 million due to increased realized marketing margins and the recording of a $1.4 million positive impact on income tax expense related to the resolution of federal income tax audits, partially offset by a decrease in unrealized marketing gains/losses.

Realized gas marketing margins increased approximately $3.4 million over the prior year due to higher average margins received and a 10 percent increase in natural gas volumes marketed. Unrealized mark-to-market losses increased $1.1 million over unrealized mark-to-market losses for the same period in 2005. (For discussion of potential volatility in energy marketing earnings related to accounting treatment of certain hedging activities at our natural gas and oil marketing operations see Trading Activities in Part 1, Item 3 of this Form 10-Q.) Results also reflect earnings from the addition of crude oil marketing to our Rocky Mountain region producer services. Operating expenses increased primarily due to increased compensation cost related to higher realized margins and an increase in bad debt provision partially offset by decreased professional fees due to a 2005 charge for a litigation settlement.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005. Income from continuing operations increased $11.1 million due to increased realized marketing margins, and the recording of a $1.4 million positive impact on income tax expense related to the resolution of federal income tax audits, partially offset by a decrease in unrealized marketing gains/losses.

Realized gas marketing margins increased approximately $16.5 million over the prior year primarily due to higher average margins received for gas marketing. Unrealized mark-to-market losses for the nine months ended September 30, 2006 were $0.3 million higher than unrealized mark-to-market losses for the same period in 2005. (For discussion of potential volatility in energy marketing earnings related to accounting treatment of certain hedging activities at our natural gas and oil marketing operations see Trading Activities in Part 1, Item 3 of this Form 10-Q.) Results also reflect earnings from the addition of crude oil marketing to our Rocky Mountain region producer services. Operating expenses increased primarily due to increased compensation cost related to higher realized margins and an increase in bad debt provision partially offset by decreased professional fees due to a 2005 charge for a litigation settlement.

Power Generation

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Revenue	$ 42,700	$ 43,076	$ 114,991	$ 121,366
Operating expenses	22,330	79,628	71,228	131,845
Operating income (loss)	$ 20,370	$ (36,552)	$ 43,763	$ (10,479)
Income (loss) from continuing operations	$ 9,839	$ (24,587)	$ 14,310	$ (14,601)

48

The following table provides certain operating statistics for our power generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Contracted power plant fleet availability	98.4%	97.8%	91.0%	98.3%

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005. Income from continuing operations increased $34.4 million due to decreases in operating expense and a federal income tax benefit partially offset by decreased revenues, lower earnings from certain power fund investments and increased interest expense. Revenues in the third quarter of 2006 decreased 1 percent compared to revenues in the third quarter of 2005.

Operating expense for the three months ended September 30, 2006, decreased $57.3 million from the same period in the prior year. The decrease in operating expenses resulted primarily from the receipt of insurance proceeds relating to the Las Vegas II power plant outages, which was presented as a $3.0 million reduction to operating expenses, lower variable costs at the Las Vegas I plant due to lower fuel costs and depreciation expense and the impact of a $50.3 million impairment charge in 2005 for the Las Vegas I power plant. During the third quarter of 2006, the Company entered into a transaction to fix the price of fuel utilized by the Las Vegas I plant during the period of October to December of 2006. This will result in lower fuel prices for the plant during this period compared to the fourth quarter of 2005.

Income from continuing operations was also affected by a $2.0 million positive impact to income tax expense related to the resolution of federal tax audits, lower earnings from certain power fund investments and increased interest expense due to increased interest rates. Earnings from power fund investments decreased $1.9 million after-tax due to the particularly strong fund earnings in 2005 and diminished earnings potential related to the ongoing liquidation of the funds.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005. Income from continuing operations increased $28.9 million due to decreases in operating expense and a federal income tax benefit partially offset by decreased revenues, lower earnings from certain power fund investments and increased interest expense. Revenues in the nine months ended September 30, 2006 decreased 5 percent compared to revenues in the same period of 2005. Lower revenues are primarily due to scheduled and unscheduled outages for repair and maintenance at the Las Vegas I and II facilities, partially offset by higher capacity revenue at the Harbor facility due to a three-year, year-round tolling agreement, which commenced April 1, 2005 and replaced a seasonal contract.

Operating expense for the nine months ended September 30, 2006, decreased $60.6 million from the same period in the prior year. The decrease in operating expenses resulted primarily from the receipt of insurance proceeds relating to the Las Vegas II power plant outages, which was presented as a $3.9 million reduction to operating expenses, lower variable costs at the Las Vegas I plant due to lower fuel costs and deprecation expense and the impact of a $50.3 million impairment charge in 2005 for the Las Vegas I power plant, partially offset by the repair and maintenance costs at the Las Vegas facilities. Las Vegas I returned to operation on April 22, 2006, while the two Las Vegas II heat recovery units returned to service on June 13, 2006 and July 4, 2006. During the third quarter of 2006, the Company entered into a transaction to fix the price of fuel utilized by the Las Vegas I plant during the period of October to December of 2006. This will result in lower fuel prices for the plant during this period compared to the fourth quarter of 2005.

Income from continuing operations was also affected by a $2.0 million positive impact to income tax expense related to the resolution of federal tax audits, lower earnings from certain power fund investments and increased interest expense due to increases in the corporate interest allocations and higher interest rates. Earnings from power fund investments decreased $4.8 million after-tax due to the particularly strong fund earnings in 2005 and diminished earnings potential related to the ongoing liquidation of the funds.

Oil and Gas

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Revenue	$ 22,969	$ 22,807	$ 69,519	$ 61,511
Operating expenses	16,524	13,504	48,748	37,412
Operating income	$ 6,445	$ 9,303	$ 20,771	$ 24,099
Income from continuing operations	$ 3,006	$ 5,109	$ 10,439	$ 14,346

The following tables provide certain operating statistics for our oil and gas segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Fuel production:				
Barrels of oil sold	109,146	102,350	295,942	302,784
Mcf of natural gas sold	2,784,080	2,908,571	8,831,697	8,614,388
Mcf equivalent sales	3,438,956	3,522,671	10,607,349	10,431,092

Production for the three months ended September 30, 2006 was affected by the unexpected loss of a productive well in the Denver-Julesburg Basin and production delays from new wells in the San Juan Basin. We expect to increase production in the last three months of 2006, as compared to the same period of 2005, as an adjusted drilling program has resulted in a reduction to our completion backlog and gas sales have started from several new wells.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Average price received*:				
Gas/Mcf**	$ 5.82	$ 6.22	$ 5.99	$ 5.72
Oil/bbl	$ 55.21	$ 40.18	$ 49.97	$ 35.30
Lease operating expenses/Mcfe	$ 1.13	$ 0.86	$ 1.17	$ 0.90
Depletion expense/Mcfe	$ 1.95	$ 1.41	$ 1.78	$ 1.19

* Net of hedges
** Exclusive of gas liquids

Location detail of our proven reserves as of December 31, 2005, not reflecting 2006 drilling activity, acquisitions or price changes, is as follows:

	Total	San Juan Basin New Mexico and Colorado	Powder River Basin Wyoming	Piceance Basin Colorado	All Other
Proved developed (Mmcfe)	109,123	58,528	33,935	2,070	14,590
Proved undeveloped(Mmcfe)	60,460	43,953	10,612	2,278	3,617
Total	169,583	102,481	44,547	4,348	18,207

Reserves reflect year-end pricing of:

December 31, 2005 gas prices:					
Year-end prices NYMEX	$ 11.23				
Year-end prices wellhead	$ 9.06	$ 9.36	$ 8.26	$ 8.87	$ 8.79
December 31, 2005 oil prices:					
Year-end prices NYMEX	$ 61.04				
Year-end prices wellhead	$ 58.52	$ 54.27	$ 58.61	$ N/A	$ 57.99

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005. Income from continuing operations decreased 41 percent in the three months ended September 30, 2006 compared to the same period in 2005 due to increased production expenses, depletion expense and increased interest expense due to higher borrowings to fund acquisition and development costs.

Revenue increased 1 percent for the three months ended September 30, 2006 compared to the three months ended September 30, 2005. Gas production decreased 4 percent and the average hedged gas price received decreased 6 percent. Oil production increased 7 percent and average hedged oil price received increased 37 percent. Oil production is also affected by an increase in the federal royalty on qualified stripper wells, which began on February 1, 2006 and in effect reduces our net share of production.

Total operating expenses increased 22 percent for the three month period ended September 30, 2006 primarily due to increased lease operating expense and depletion expense. The lease operating expenses per Mcfe sold (LOE/MCFE) increased 31 percent primarily as a result of higher industry costs, new San Juan compression costs, the East Blanco amine plant costs and additional operating costs associated with compression and gas treatment for the recently acquired Piceance Basin properties. Depletion expense per Mcfe increased 38 percent. The average depletion rate per Mcfe is a function of capitalized costs, projected future development costs and the related underlying reserves in the periods presented. The increased depletion rate is due to increases in current year finding costs and higher estimated future development costs as well as the higher average cost of recently acquired reserves and their future development costs.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005. Income from continuing operations decreased 27 percent in the nine months ended September 30, 2006 compared to the same period in 2005 due to increased production expenses, depletion expense and increased interest expense due to higher borrowings to fund acquisition and development costs offset by an increase in revenues.

Revenue increased 13 percent for the nine months ended September 30, 2006 compared to the nine months ended September 30, 2005. Gas production increased 3 percent and average hedged gas price received increased 5 percent. A 42 percent increase in average hedged oil price received was partially offset by a 2 percent decrease in oil production, primarily due to an increase in the federal royalty on qualified stripper wells, which began on February 1, 2006 and in effect reduces our net share of production.

Total operating expenses increased 30 percent for the nine month period ended September 30, 2006 primarily due to increased lease operating expense and depletion expense. The lease operating expenses per Mcfe sold (LOE/MCFE) increased 30 percent primarily as a result of higher industry costs, new San Juan compression costs, the East Blanco amine plant costs and new operating costs associated with compression and gas treatment for the recently acquired Piceance Basin properties. Depletion expense per Mcfe increased 50 percent. The average depletion rate per Mcfe is a function of capitalized costs, projected future development costs and the related underlying reserves in the periods presented. The increased depletion rate is due to increases in current year finding costs and higher estimated future development costs as well as the higher average cost of recently acquired reserves and their future development costs.

On March 17, 2006, we acquired certain oil and gas assets of Koch Exploration Company, LLC. The assets include approximately 40 Bcfe of proved reserves, including approximately 31 Bcfe of proved undeveloped reserves which are substantially all gas, and associated midstream and gathering assets. In addition, on August 30, 2006 we acquired from a third party most of the remaining working interests associated with this acquisition. This includes approximately 22.4 Bcfe of proven reserves, of which 17.9 Bcfe are proved undeveloped reserves. The associated acreage position is located in the Piceance Basin in Colorado.

Coal Mining

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Revenue	$ 9,446	$ 8,482	$ 25,484	$ 24,861
Operating expenses	7,172	6,824	20,984	19,401
Operating income	$ 2,274	$ 1,658	$ 4,500	$ 5,460
Income from continuing operations	$ 1,908	$ 1,643	$ 4,091	$ 4,860

The following table provides certain operating statistics for our coal mining segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Fuel production:				
Tons of coal sold	1,244,450	1,172,360	3,478,800	3,474,050

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005.

Income from continuing operations from our Coal mining segment increased 16 percent. Revenue increased 11 percent for the three month period ended September 30, 2006 compared to the same period in 2005 due to a 6 percent increase in tons of coal sold. Coal production increased primarily due to increased train load-out sales. Operating expenses increased 5 percent during the three months ended September 30, 2006 primarily due to increased overburden expense resulting from a change in accounting rules requiring overburden removal to be expensed as incurred, increased depreciation expense and increased mineral taxes, partially offset by lower general and administrative expense.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005.

Income from continuing operations from our Coal mining segment decreased 16 percent. Revenue increased 3 percent for the nine month period ended September 30, 2006 compared to the same period in 2005. Coal production was flat with the prior year as scheduled and unscheduled plant outages were offset by increased train load-out sales. Operating expenses increased 8 percent during the nine months ended September 30, 2006 primarily due to increased overburden expense resulting from a change in accounting rules requiring overburden removal to be expensed as incurred and higher depreciation expense partially offset by lower general and administrative expense.

Corporate

Decreased costs in the three and nine months ended September 30, 2006, compared to the same periods in 2005, are primarily the result of the write-off and expensing of certain capitalized project development costs of approximately $8.9 million and $9.5 million for the three and nine month periods ended September 30, 2005, and increased allocation of interest costs partially offset by current period development cost expense.

Critical Accounting Policies

On January 1, 2006, we adopted the provisions of SFAS 123(R), as detailed in Note 11 of the Notes to Condensed Consolidated Financial Statements included herein. The primary change resulting from adoption was the required recognition of compensation expense for stock options issued. Compensation expense for stock options was approximately $0.1 million and $0.4 million for the three and nine month periods ended September 30, 2006. The adoption did not have a significant effect on how we recognize compensation expense for our other forms of stock-based compensation.

Other than noted above, there have been no other material changes in our critical accounting policies from those reported in our 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission. For more information on our critical accounting policies, see Part II, Item 7 of our 2005 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the nine month period ended September 30, 2006, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on our common stock, to pay our long-term debt maturities and the debt prepayment associated with the Colorado debt refinancing, and to fund a portion of our property, plant and equipment additions. We plan to fund future property and investment additions primarily through a combination of operating cash flow and increased short-term and long-term debt.

Cash flows from operations increased $40.2 million for the nine-month period ended September 30, 2006 compared to the same period in the prior year as a $46.3 million increase in income from continuing operations was affected by the following:

A $50.3 million impairment charge in 2005 for the Las Vegas I power plant included as an expense in 2005, but which did not impact cash flows.

A $16.1 million decrease in cash flows from working capital changes. This decrease resulted from reduced cash flows from changes in net accounts receivable and accounts payable partially offset by a $12.7 million increase in cash flows from sales or purchases of materials, supplies and fuel. This is primarily related to natural gas held in storage by our natural gas and crude oil marketing business which fluctuates based on economic decisions reflecting current market conditions.

A $49.7 million increase related to deferred income taxes. This increase was primarily the result of accelerated deductions associated with property, plant and equipment and the timing of deductibility of the 2005 Las Vegas I impairment and write-off of capitalized development costs.

Increased cash flows from changes in deferred regulatory assets and liabilities as the cost of energy supplied is lower than costs recovered through utility rate adjustments.

During the nine months ended September 30, 2006, we had cash outflows from investing activities of $189.5 million, which was primarily due to the following:

Cash outflows of $229.7 million from property, plant and equipment additions. These outflows include approximately $75.4 million for the acquisition of oil and gas assets in the Piceance Basin in Colorado, and approximately $54.6 million related to the construction of our Wygen II power plant.

Cash inflows of approximately $40.7 million resulting from the sale of our Texas based crude oil marketing and transportation assets.

During the nine months ended September 30, 2006, we had cash flows from financing activities of $28.9 million, primarily due to $92 million of increased borrowings on our credit facility, partially offset by the payment of cash dividends on common stock, a $21.3 million net payment related to the Black Hills Colorado project debt refinancing, as well as payment of long-term debt maturities.

54

Dividends

Dividends paid on our common stock totaled $33.0 million during the nine months ended September 30, 2006, or $0.99 per share. This reflects a 3 percent increase, as approved by our board of directors in January 2006, from the 2005 dividend level. 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.

Short-Term Liquidity and Financing Transactions

Our principal sources of short-term liquidity are our revolving bank facility and cash provided by operations. Our liquidity position remained strong during the first nine months of 2006. As of September 30, 2006, we had approximately $47.7 million of cash unrestricted for operations. Approximately $3.2 million of the cash balance at September 30, 2006 was restricted by subsidiary debt agreements that limit our subsidiaries ability to dividend cash to the parent company.

The $400 million revolving bank facility has a five year term, expiring May 4, 2010. The facility contains a provision which allows the facility size to be increased by up to an additional $100 million through the addition of new lenders, or through increased commitments from existing lenders, but only with the consent of such lenders. The cost of borrowings or letters of credit issued under the new facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70.0 basis points over LIBOR (which equates to a 6.02 percent one-month borrowing rate as of September 30, 2006).

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At September 30, 2006, we had $147 million of borrowings and $49.7 million of letters of credit issued on our revolving credit facility with a remaining borrowing capacity of $203.3 million available.

The bank 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; 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 lender to terminate the remaining commitment and accelerate all principal and interest outstanding.

A default under the bank facility may be triggered by events such as a failure to comply with financial covenants or certain other covenants under the bank 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 bank facility would permit the participating banks to restrict the Company s 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 bank facility prohibits the Company from paying cash dividends unless no default or no event of default exists prior to, or would result, after giving effect to such action.

Our consolidated net worth was $780.7 million at September 30, 2006, which was approximately $108.9 million in excess of the net worth we were required to maintain under the bank facility. Our long-term debt ratio at September 30, 2006 was 44.7 percent, our total debt leverage (long-term debt and short-term debt) was 50.5 percent, and our recourse leverage ratio was approximately 49.9 percent.

On May 24, 2006 the Company entered into an Amended and Restated Credit Agreement for the project financing floating rate debt for Wygen I. The agreement extended the maturity date of the $111.1 million tranche of the financing from June 2006 to June 2008 to coincide with the maturity date of the remaining $17.2 million tranche.

In addition, Enserco Energy Inc., our energy marketing unit, entered into a Second Amended and Restated Credit Agreement on June 1, 2006 for a $260 million uncommitted, discretionary line of credit to provide support for the purchase and sale of natural gas and crude oil. The line of credit is secured by all of Enserco s assets and expires on May 11, 2007. At September 30, 2006, there were outstanding letters of credit issued under the facility of $144.1 million, with no borrowing balances outstanding on the facility.

On July 12, 2006 the Company s subsidiary, Black Hills Colorado, LLC, entered into a Second Amended and Restated Credit Agreement to refinance the floating rate project debt for the Valmont and Arapahoe plants in the amount of $90.0 million. The maturity date of the amortizing borrowings is July, 2013. In conjunction with the refinancing, the Company made a payment in the amount of $21.3 million on the $111.3 million principal outstanding at June 30, 2006 and expensed approximately $0.7 million of unamortized deferred finance costs associated with the First Amended and Restated Credit Agreement.

Our corporate credit rating by Moody s Investors Service remained unchanged at Baa3 during the first nine months of 2006; the outlook is stable. On May 1, 2006, Standard & Poor s Ratings Services (S&P) affirmed its BBB- corporate credit rating on the Company with outlook negative and removed the rating from CreditWatch with negative implications. On September 20, 2006, S&P again affirmed its BBB- corporate credit rating on the Company with outlook negative. In reviewing the outlook, S&P stated that it would lower our credit ratings if business risk does not improve over the next six to twelve months, and cited various factors which would be considered necessary to constitute a change in business risk.

Our ability to obtain additional financing, if necessary, will depend upon a number of factors, including our future performance and financial results, and capital market conditions. We can provide no assurance that we will be able to raise additional capital on reasonable terms or at all.

There have been no other material changes in our forecasted liquidity requirements from those reported in Item 7 of our 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Guarantees

During the nine months ended September 30, 2006 the Company had the following changes to its guarantees:

Issued a Guarantee for the payment obligations for the Valmont and Arapahoe project financing floating rate debt of Black Hills Colorado, LLC, to the Bank of Nova Scotia, as administrative agent, for up to $30 million, expiring in 2013.

Issued and amended a Guarantee for payment under various transactions by Cheyenne Light with Tenaska Marketing Ventures for $2.0 million, expiring in 2007.

Issued an Amended and Restated Guarantee in favor of Wygen Funding, Limited Partnership, which continues the Company s guarantee obligations under the Wygen I plant lease.

Extinguished a guarantee of up to $3.0 million of Enserco Energy Inc. s obligations to Fortis Capital Corp. and other lenders under its credit facility.

Expiration of a guarantee of an interest rate swap transaction with Union Bank of California.

At September 30, 2006, we had guarantees totaling $187.9 million in place.

Capital Requirements

During the nine months ended September 30, 2006, capital expenditures were approximately $260.7 million for property, plant and equipment additions, which includes approximately $31.5 million of accrued liabilities. We currently expect capital expenditures for the entire year 2006 to approximate $302.2 million.

We continue to actively evaluate potential future acquisitions and other growth opportunities in accordance with our disclosed business strategy. We are not obligated to a project until a definitive agreement is entered into and cannot guarantee we will be successful on any potential projects. Future projects are dependent upon the availability of economic opportunities and, as a result, actual expenditures may vary significantly from forecasted estimates.

New Accounting Pronouncements

Other than the new pronouncements reported in our 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission and those discussed in Notes 3 and 4 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.

57

SAFE HARBOR FOR FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q includes forward-looking statements as defined by the Securities and Exchange Commission, or SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including the risk factors described in Item 1A. of Part I of our 2005 Annual Report on Form 10-K and in Item 1A. of Part II of this Quarterly Report on Form 10-Q filed with the SEC, and the following:

Obtaining adequate cost recovery for our retail operations through regulatory proceedings and receiving unfavorable rulings in the periodic applications to recover costs for fuel and purchased power in our regulated utilities;

The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;

Our ability to successfully maintain or improve our corporate credit rating;

The construction, start up and operation of power generating facilities may involve unanticipated charges or delays that could negatively impact the Company s business and its results of operation;

The completion of acquisitions or divestitures for which definitive agreements have been executed could be delayed or may not occur or may not receive regulatory approval if required;

The volumes of production from our oil and gas development properties, which may be dependent upon issuance by federal, state, and tribal governments, or agencies thereof, of drilling, environmental and other permits, and the availability of specialized contractors, work force, and equipment;

The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;

The timing and extent of scheduled and unscheduled outages of power generation facilities;

Our ability to successfully integrate and profitably operate any future acquisitions;

The possibility that we may be required to take impairment charges to reduce the carrying value of some of our long-lived assets when indicators of impairment emerge;

Numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs;

Changes in business and financial reporting practices arising from the repeal of the Public Utility Holding Company Act of 1935 and other provisions of the recently enacted Energy Policy Act of 2005;

Our ability to remedy any deficiencies that may be identified in the review of our internal controls;

The timing, volatility and extent of changes in energy-related and commodity prices, interest rates, energy and commodity supply or volume, the cost and availability of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;

Our effective use of derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;

The creditworthiness of counterparties to trading and other transactions, and defaults on amounts due from counterparties;

The amount of collateral required to be posted from time to time in our transactions;

Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;

Changes in state laws or regulations that could cause us to curtail our independent power production;

Weather and other natural phenomena;

Industry and market changes, including the impact of consolidations and changes in competition;

The effect of accounting policies issued periodically by accounting standard-setting bodies;

The cost and effects on our business, including insurance, resulting from terrorist actions or natural disasters and responses to such actions or events;

The outcome of any ongoing or future litigation or similar disputes and the impact on any such outcome or related settlements;

Capital market conditions, which may affect our ability to raise capital on favorable terms;

Price risk due to marketable securities held as investments in benefit plans;

General economic and political conditions, including tax rates or policies and inflation rates; and

Other factors discussed from time to time in our other filings with the SEC.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events, or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Trading Activities

The following table provides a reconciliation of our activity in energy trading contracts that meet the definition of a derivative under SFAS 133 and that were marked-to-market during the nine months ended September 30, 2006 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2005	$	5,879
Net cash settled during the period on positions that existed at December 31, 2005		(20,212)
Unrealized gain on new positions entered during the period and still existing at September 30, 2006		7,327
Realized gain on positions that existed at December 31, 2005 and were settled during the period		13,484
Unrealized loss on positions that existed at December 31, 2005 and still exist at September 30, 2006		(2,530)
Total fair value of energy marketing positions at September 30, 2006	$	3,948

____

(a) The fair value of positions marked-to-market consists of derivative assets/liabilities and natural gas inventory that has been designated as a hedged item and marked-to-market as part of a fair value hedge, as follows (in thousands):

	September 30, 2006	June 30, 2006	March 31, 2006	December 31, 2005
Net derivative assets/(liabilities)	$ 33,738	$ 13,585	$ 13,739	$ (764)
Fair value adjustment recorded in material, supplies and fuel	(29,790)	(4,288)	(5,353)	6,643
	$ 3,948	$ 9,297	$ 8,386	$ 5,879

On January 1, 2003, the Company adopted EITF 02-3. The adoption of EITF 02-3 resulted in certain energy trading activities no longer being accounted for at fair value, therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities and our expected cash flows from those operations. EITF Issue No. 98-10 Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF 98-10) was superseded by EITF 02-3 and allowed a broad interpretation of what constituted trading activity and hence what would be marked-to-market. EITF 02-3 took a much narrower view of what trading activity should be marked-to-market, limiting mark-to-market treatment primarily to only those contracts that meet the definition of a derivative under SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities (SFAS 133). At our natural gas and crude oil marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in very limited 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.

The sources of fair value measurements for natural gas marketing derivative contracts were as follows (in thousands):

	Maturities		
Source of Fair Value	Less than 1 year	1 2 years	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ 2,659	$ 194	$ 2,853
Prices provided by other external sources	1,533	(438)	1,095
Modeled			
Total	$ 4,192	$ (244)	$ 3,948

The following table presents a reconciliation of our September 30, 2006 energy marketing positions recorded at fair value under generally accepted accounting principles (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). The approach used in determining the non-GAAP measure is consistent with our previous accounting methods under EITF 98-10. In accordance with generally accepted accounting principles and industry practice, the Company includes a Liquidity Reserve in its GAAP marked-to-market fair value. This Liquidity Reserve accounts for the estimated impact of the bid/ask spread in a liquidation scenario under which the Company is forced to liquidate its forward book on the balance sheet date.

Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 3,948
Increase in fair value of inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	14,859
Fair value of all forward positions (Non-GAAP)	18,807
Liquidity Reserve included in GAAP marked-to-market fair value	1,809
Fair value of all forward positions excluding the Liquidity Reserve (Non-GAAP)	$ 20,616

There have been no material changes in market risk faced by us from those reported in our 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission. For more information on market risk, see Part II, Item 7 and 7A in our 2005 Annual Report on Form 10-K, and Note 16 of our 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 2006 and 2007 natural gas and crude oil production. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (Mmbtu/day)	Price
San Juan El Paso	07/12/2005	Swap	04/06 10/06	5,000	$ 7.00
San Juan El Paso	12/14/2005	Swap	11/06 03/07	5,000	$ 10.25
San Juan El Paso	04/03/2006	Swap	11/06 03/07	5,000	$ 8.50
San Juan El Paso	06/15/2006	Swap	11/06 03/07	2,500	$ 8.52
San Juan El Paso	06/15/2006	Swap	11/06 03/07	2,500	$ 8.59
San Juan El Paso	04/03/2006	Swap	04/07 10/07	5,000	$ 7.46
San Juan El Paso	06/02/2006	Swap	04/07 10/07	2,500	$ 7.20
San Juan El Paso	11/03/2006	Swap	04/07 10/07	5,000	$ 6.91
San Juan El Paso	11/03/2006	Swap	11/07 03/08	5,000	$ 7.86
CIG	07/28/2006	Swap	09/06 03/08	2,500	$ 7.60
CIG	07/31/2006	Swap	09/06 03/08	2,500	$ 7.85

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (barrels/month)	Price
NYMEX	10/06/2004	Swap	Calendar 2006	10,000	$ 41.00
NYMEX	12/14/2005	Put	Calendar 2006	5,000	$ 55.00
NYMEX	01/12/2006	Put	02/06 12/06	5,000	$ 65.50
NYMEX	07/29/2005	Swap	Calendar 2007	5,000	$ 61.00
NYMEX	08/04/2005	Swap	Calendar 2007	5,000	$ 62.00
NYMEX	01/04/2006	Swap	Calendar 2007	5,000	$ 65.00
NYMEX	04/03/2006	Put	Calendar 2007	5,000	$ 70.00

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 (Exchange Act)) as of September 30, 2006. Based on their evaluation, they have concluded that our disclosure controls and procedures are adequate and effective to ensure that material information relating to us that is required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the required time periods.

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2006 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 20 in Item 8 of the Company s 2005 Annual Report on Form 10-K and Note 17 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 17 is incorporated by reference into this item.

Item 1A. Risk Factors

There have been no material changes in our Risk Factors from those reported in Item 1A. of Part I of our 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2006 July 31, 2006		$		
August 1, 2006 August 31, 2006	103[1]	$ 34.90		
September 1, 2006 September 30, 2006	284[2]	$ 35.18		

Total	387	$ 35.11

____

(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Restricted Stock Plan for the payment of taxes associated with the vesting of shares of Restricted Stock.
(2) Shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan.

63

Item 6. Exhibits

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/ Mark T. Thies
Mark T. Thies, Executive Vice President and
Chief Financial Officer

Dated: November 8, 2006

EXHIBIT INDEX

Exhibit Number	Description
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.