GeoMet, Inc.
Form 10-Q
August 07, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission File Number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification Number)**

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

(Address of principal executive offices and telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

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. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ¨ Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes x No

As of August 1, 2009, there were 39,468,046 shares issued and outstanding of GeoMet, Inc. s common stock, par value $0.001 per share.

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Part I. Financial Information

Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	June 30, 2009	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,220,659	$ 2,096,561
Accounts receivable, both amounts net of allowance of $60,848	2,508,512	5,364,456
Inventory	2,689,620	3,339,228
Derivative assets	5,433,247	6,596,360
Other current assets	191,686	541,311
Total current assets	12,043,724	17,937,916
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	454,741,001	447,968,536
Unevaluated gas properties, not subject to amortization		5,017
Other property and equipment	3,491,139	3,429,890
Total property and equipment	458,232,140	451,403,443
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(266,521,406)	(93,104,323)
Property and equipment net	191,710,734	358,299,120
Other noncurrent assets:		
Derivative assets	12,107	723,669
Deferred income taxes	19,471,540	
Other	593,758	639,648
Total other noncurrent assets	20,077,405	1,363,317
TOTAL ASSETS	$ 223,831,863	$ 377,600,353
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 4,628,527	$ 13,384,675
Accrued liabilities	3,109,327	2,623,640
Deferred income taxes	1,630,128	2,426,798
Derivative liabilities	917,060	714,903
Asset retirement liability	114,443	117,423
Current portion of long-term debt	118,427	111,767
Total current liabilities	10,517,912	19,379,206
Long-term debt	122,285,305	117,117,955
Asset retirement liability	4,586,548	4,348,938
Other long-term accrued liabilities	89,599	105,890

Derivative liabilities	213,888	374,489
Deferred income taxes		43,841,950
TOTAL LIABILITIES	137,693,252	185,168,428
Commitments and contingencies (Note 10)		
Stockholders Equity:		
Preferred stock, $0.001 par value authorized 10,000,000, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 39,468,046 and 39,305,152 at June 30, 2009 and December 31, 2008, respectively	39,468	39,050
Treasury stock 10,432 shares	(93,811)	(93,811)
Paid-in capital	189,303,602	188,692,242
Accumulated other comprehensive loss	(2,187,529)	(2,399,992)
Retained (deficit) earnings	(100,689,228)	6,422,772
Less notes receivable	(233,891)	(228,336)
Total stockholders equity	86,138,611	192,431,925
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 223,831,863	$ 377,600,353

See accompanying Notes to Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenues:				
Gas sales	$ 6,837,910	$ 20,700,928	$ 16,290,419	$ 36,282,106
Operating fees	76,923	203,528	174,934	501,157
Total revenues	6,914,833	20,904,456	16,465,353	36,783,263
Expenses:				
Lease operating expense	3,348,170	3,640,244	7,917,487	7,391,570
Compression and transportation expense	1,364,841	1,005,386	2,814,965	2,048,195
Production taxes	240,593	634,109	607,655	1,056,045
Depreciation, depletion and amortization	1,981,707	2,489,266	5,018,438	4,948,595
Impairment of gas properties	27,582,106		167,294,577	
General and administrative	2,180,889	2,887,237	5,153,501	5,379,707
Realized (gains) losses on derivative contracts	(2,733,816)	1,493,064	(5,457,120)	631,236
Unrealized losses from the change in market value of open derivative contracts	2,144,115	12,097,929	1,958,232	20,744,592
Total operating expenses	36,108,605	24,247,235	185,307,735	42,199,940
Operating loss	(29,193,772)	(3,342,779)	(168,842,382)	(5,416,677)
Other income (expense):				
Interest income	5,674	13,286	15,634	20,063
Interest expense (net of amounts capitalized)	(1,418,402)	(1,117,276)	(2,401,447)	(2,420,469)
Other	8,750	34,892	7,732	29,343
Total other income (expense):	(1,403,978)	(1,069,098)	(2,378,081)	(2,371,063)
Loss before income taxes	(30,597,750)	(4,411,877)	(171,220,463)	(7,787,740)
Income tax benefit	11,211,554	1,235,253	64,108,463	2,469,173
Net loss	$ (19,386,196)	$ (3,176,624)	$ (107,112,000)	$ (5,318,567)
Earnings per share:				
Net loss				
Basic	$ (0.50)	$ (0.08)	$ (2.75)	$ (0.14)
Diluted	$ (0.50)	$ (0.08)	$ (2.75)	$ (0.14)
Weighted average number of common shares:				
Basic	39,122,570	39,271,342	39,024,353	39,139,812
Diluted	39,122,570	39,271,342	39,024,353	39,139,812

See accompanying Notes to Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive Loss

(Unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net loss	$ (19,386,196)	$ (3,176,624)	$ (107,112,000)	$ (5,318,567)
Gain (loss) on foreign currency translation adjustment	85,871	139,335	181,264	(331,884)
Gain (loss) on interest rate swap	32,138	541,975	31,199	(5,186)
Other comprehensive loss	$ (19,268,187)	$ (2,495,314)	$ (106,899,537)	$ (5,655,637)

See accompanying Notes to Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2009	2008
Cash flows provided by operating activities:		
Net loss	$ (107,112,000)	$ (5,318,567)
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	5,018,438	4,948,595
Impairment of gas properties	167,294,577	
Amortization of debt issuance costs	102,481	85,981
Deferred income tax benefit	(64,120,962)	(2,469,173)
Unrealized losses from the change in market value of open derivative contracts	1,958,232	20,744,592
Stock-based compensation	501,114	383,606
Loss on sale of other assets	31,076	20,512
Accretion expense	212,640	167,944
Changes in operating assets and liabilities:		
Accounts receivable	2,881,388	(2,778,368)
Inventory	(182,207)	(55,670)
Other current assets	349,625	166,546
Accounts payable	(3,903,241)	1,551,344
Other accrued liabilities	211,538	127,022
Net cash provided by operating activities	3,242,699	17,574,364
Cash flows used in investing activities:		
Capital expenditures	(9,264,458)	(18,600,519)
Proceeds from sale of other property and equipment	19,165	26,000
Other assets	(56,593)	25,071
Net cash used in investing activities	(9,301,886)	(18,549,448)
Cash flows provided by financing activities:		
Proceeds from exercise of stock options		75,025
Proceeds from revolver borrowings	28,550,000	50,500,000
Payments on revolver	(23,300,000)	(47,000,000)
Purchase of treasury stock	(613)	(23,359)
Payments on other debt	(75,990)	(69,877)
Net cash provided by financing activities	5,173,397	3,481,789
Effect of exchange rate changes on cash	9,888	(10,878)
(Decrease) increase in cash and cash equivalents	(875,902)	2,495,827
Cash and cash equivalents at beginning of period	2,096,561	1,540,516
Cash and cash equivalents at end of period	$ 1,220,659	$ 4,036,343
Significant noncash investing and financing activities:		
Accrued capital expenditures	$ 382,668	$ 3,349,315

See accompanying Notes to Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(Unaudited)

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet, Company, we, or our) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are an independent natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coal bed methane) and non-conventional shallow gas. Our principal operations and producing properties are located in Alabama, West Virginia, Virginia and Canada.

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements for the fiscal year ended December 31, 2008 and the accompanying notes included in our Annual Report on Form 10-K, which we filed with the Securities and Exchange Commission (the SEC) on March 13, 2009.

Note 2 Recent Pronouncements

FASB Accounting Standards Codification In June 2009, the FASB issued the FASB Accounting Standards Codification (Codification). The Codification will become the single source for all authoritative GAAP recognized by the FASB to be applied for financial statements issued for periods ending after September 15, 2009. The Codification does not change GAAP and will not affect our financial position, results of operations or liquidity.

SFAS No. 165, Subsequent Events In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*. The standard does not require significant changes regarding recognition or disclosure of subsequent events, but does require disclosure of the date through which subsequent events have been evaluated for disclosure and recognition. The standard is effective for financial statements issued after June 15, 2009. The implementation of this standard did not have a significant impact on the financial statements of the Company. Subsequent events through the filing date of this Quarterly Report on Form 10-Q have been evaluated for disclosure and recognition.

Recent FASB Staff Positions On July 1, 2009, we adopted three FASB Staff Positions (FSP) effective for interim and annual periods ending after June 15, 2009 as follows:

(1) Determining Fair Value When Market Activity Has Decreased FSP FAS 157-4, which applies to all assets and liabilities (i.e., financial and nonfinancial), reemphasizes that the objective of fair value remains unchanged (i.e., an exit price notion). FSP FAS 157-4 provides application guidance on measuring fair value when the volume and level of activity has significantly decreased and identifying transactions that are not orderly. FSP FAS 157-4 also emphasizes that an entity cannot presume that an observable transaction price is not orderly even when there has been a significant decline in the volume and level of activity. FSP FAS 157-4 also requires enhanced disclosures.

(2) Other-Than-Temporary Impairment (OTTI) FSP FAS 115-2/124-2 provides a new OTTI model for debt securities only. Equity securities will continue to apply the existing OTTI model. The FSP shifts the focus for debt securities from an entity s intent to hold until recovery to its intent to sell. FSP FAS 115-2/124-2 also requires entities to initially apply the provisions of the standard to certain previously other-than-temporarily impaired debt instruments existing as of the date of initial adoption by making a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The cumulative-effect adjustment

reclassifies the noncredit portion of a previously other-than-temporarily impaired debt security held as of the date of initial adoption from retained earnings to accumulated other comprehensive income. FSP FAS 115-2/124-2 also requires enhanced disclosures.

(3) Interim Fair Value Disclosures for Financial Instruments FSP FAS 107-1/APB 28-1 expands the fair value disclosures required for all financial instruments within the scope of Statement 107 to interim periods. The disclosure requirements of FSP FAS 107-1/APB 28-1 only apply to public entities. FSP FAS 107-1/APB 28-1 does not require interim disclosures of credit or market risks also discussed in Statement 107.

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The adoption of the aforementioned three FASB Staff Positions had no material impact on Consolidated Financial Statements (Unaudited) or the accompanying Notes to Consolidated Financial Statements (Unaudited).

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

Commodity Prices Economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used.

Disclosure of Unproved Reserves Probable and possible reserves may be disclosed separately on a voluntary basis.

Proved Undeveloped Reserve Guidelines Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.

Reserve Estimation Using New Technologies Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Reserve Personnel and Estimation Process Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

Non-Traditional Resources The definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. We are currently evaluating the new rules and assessing the impact they will have on our reported proved natural gas reserves. The SEC is coordinating with the Financial Accounting Standards Board to obtain the revisions necessary to SFAS 19, Financial Accounting and Reporting by Oil and Gas Producing Companies , and SFAS 69 to provide consistency with the new rules.

In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC will consider delaying the compliance date.

Note 3 Loss Per Share

Loss Per Share of Common Stock Basic loss per share is calculated by dividing net loss by the weighted average number of shares of common stock outstanding during the period. Fully diluted loss per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net loss by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive loss per share considers the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of the numerator and denominator is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net loss per share:				
Basic-net loss per share	$ (0.50)	$ (0.08)	$ (2.75)	$ (0.14)

Diluted-net loss per share	$ (0.50)	$ (0.08)	$ (2.75)	$ (0.14)
Numerator:				
Net loss available to common stockholders	$ (19,386,196)	$ (3,176,624)	$ (107,112,000)	$ (5,318,567)
Denominator:				
Weighted average shares outstanding-basic	39,122,570	39,271,342	39,024,353	39,139,812
Add potentially dilutive securities:				
Stock options				
Dilutive securities	39,122,570	39,271,342	39,024,353	39,139,812

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Diluted net loss per share for the three and six months ended June 30, 2009 excluded the effect of outstanding options to purchase 2,444,333 shares and 329,410 shares of restricted stock because we reported a net loss, which caused options to be anti-dilutive. Diluted net loss per share for the three and six months ended June 30, 2008 excluded the effect of outstanding options to purchase 1,916,871 shares because we reported a net loss which caused options to be anti-dilutive.

Note 4 Gas Properties

The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the SEC. Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into U.S. and Canadian cost centers.

Gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved natural gas reserves.

Estimation of proved natural gas reserves relies on petroleum engineering techniques and assumptions, as well as professional judgment, and the use of factors that cannot be precisely determined. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during future reporting periods. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of proved natural gas reserves which would have a significant impact on the depreciation, depletion and amortization rate.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling limitation test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling limitation test is imposed separately for our U.S. and Canadian cost centers. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling limitation test is calculated using natural gas prices in effect as of the balance sheet date, adjusted for location differentials, held constant over the life of the reserves; however, as allowed by the guidelines of the SEC, significant changes in natural gas prices subsequent to quarter end are used in the ceiling limitation test. In addition, subsequent to the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143), the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling limitation test calculation.

At June 30, 2009, the carrying value of the Company s gas properties in the U.S. and Canada exceeded the full cost ceiling limitation based upon the natural gas prices per Mcf in effect as of the balance sheet date, adjusted for location differentials, which were approximately $4.00 and $3.57, respectively. For the three months ended June 30, 2009, impairments recorded to gas properties were:

	United States	Canada	Total
Impairment of gas properties	$ 27,082,174	$ 499,932	$ 27,582,106
Deferred income tax benefit	(10,345,392)		(10,345,392)
Impairment of gas properties, net of tax	$ 16,736,782	$ 499,932	$ 17,236,714

For the six months ended June 30, 2009, impairments recorded to gas properties were:

	United States	Canada	Total
Impairment of gas properties	$ 165,453,805	$ 1,840,772	$ 167,294,577
Deferred income tax benefit	(63,203,421)		(63,203,421)

Impairment of gas properties, net of tax	$ 102,250,384	$ 1,840,772	$ 104,091,156

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Note 5 Asset Retirement Liability

We record an asset retirement obligation (ARO) on the consolidated balance sheets and capitalize the asset retirement costs in gas properties in the period in which the retirement obligation is incurred. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated up to the estimated settlement date by an assumed inflation factor, which is then discounted back to the date we incurred the abandonment obligation using an assumed interest rate. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed interest rate.

The following table details the changes to our asset retirement liability for the six months ended June 30, 2009:

Current portion of liability at January 1, 2009	$ 117,423
Add: Long-term asset retirement liability at January 1, 2009	4,348,938
Asset retirement liability at January 1, 2009	4,466,361
Liabilities incurred	11,842
Liabilities settled	(4,907)
Accretion	215,332
Foreign currency translation	12,363
Asset retirement liability at June 30, 2009	4,700,991
Less: Current portion of liability	(114,443)
Long-term asset retirement liability	$ 4,586,548

Note 6 Derivative Instruments and Hedging Activities

The energy markets have historically been volatile, and there can be no assurance that future natural gas prices will not be subject to wide fluctuations. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily using derivative instruments in the form of three-way collars, traditional collars and swaps. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu below the bought floor. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments may materially affect our financial position and results of operations as a result of changes in the estimated market value of our natural gas derivatives. Nevertheless, we believe that the use of these instruments will not have a material adverse effect on our cash flows.

The following (gains) losses on our hedging instruments included in the consolidated statements of operations and other comprehensive loss (OCL) are as follows:

The Effect of Derivative Instruments on the Consolidated Statements of Operations and

Other Comprehensive Loss for the three and six months ended June 30, 2009 and 2008

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative			
		Three months ended June 30,		Six months ended June 30,	
		2009	2008	2009	2008
Derivatives designated as hedging instruments under SFAS 133					
Interest rate swaps	Interest expense (net of amounts capitalized)	$ 259,293	$ 66,063	$ 468,533	$ 18,299
Total gain (loss)		$ 259,293	$ 66,063	$ 468,533	$ 18,299
Derivatives not designated as hedging instruments under SFAS 133					
Natural gas collar positions	Realized gains on derivative contracts	$ (2,733,816)	$ 1,493,064	$ (5,457,120)	$ 631,236
Natural gas collar positions	Unrealized (gains) losses from the change in market value of open derivative contracts	2,144,115	12,097,929	1,958,232	20,744,592
Total gain (loss)		$ (589,701)	$ 13,590,993	$ (3,498,888)	$ 21,375,828

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	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Derivatives in Statement 133 Cash Flow Hedging Relationships - Interest Rate Swaps				
Location of Gain or (Loss) Reclassified from Accumulated OCL into Income (Effective Portion)		Interest expense		
Amount of Gain or (Loss) Recognized in OCL on Derivative (Effective Portion)	$ (210,329)	$ 701,849	$ (426,531)	$ (10,706)
Location of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	-	Interest expense		—
Amount of Gain or (Loss) Reclassified from Accumulated OCL into Income (Effective Portion)	$ (259,293)	$ (66,063)	$ (468,533)	$ (18,299)
		Other income/(expense)		
Amount of Gain or (Loss) Recognized in income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	$	$	$	$

Commodity Price Risk and Related Hedging Activities

At June 30, 2009, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
July through October 2009	738,000	(1)	$ 7.50	$ 5.25	$ 1,583,705
July through October 2009	738,000	(1)	$ 8.50	$ 6.50	1,449,387
July through October 2009 (1)	1,476,000	$ 4.50	$ 3.70	(1)	23,172
November 2009 through March 2010	906,000	$ 11.20	$ 9.50	$ 7.00	1,966,202
November 2009 through March 2010	604,000	$ 6.65	$ 5.50	$ 3.50	133,495
April through October 2010	856,000	$ 6.80	$ 5.50	$ 3.50	$ (28,533)
					$ 5,127,428

(1) In connection with the July through October 2009 natural gas collar related to natural gas volumes of 1,476,000 MMBtu/day denoted above, the Company eliminated the existing $10.00 sold ceilings with respect to all three-way-collars through October 2009.

At June 30, 2009, we had the following natural gas swap position:

Period	Volume (MMBtu)	Price	Fair Value
July through October 2009	492,000	$ 4.47	$ 234,369

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

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We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At June 30, 2009, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate (1)	Notional amount	Fair Value
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%	$ 15,000,000	$ (575,685)
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%	$ 10,000,000	$ (231,422)
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%	$ 10,000,000	$ (120,248)
Floating-to-fixed swap	5/13/2008	5/13/2010	3.07%	$ 5,000,000	$ (105,103)
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	$ (14,933)
					$ (1,047,391)

(1) The floating rate paid by the counterparty is the British Bankers Association LIBOR rate.

For the three and six months ended June 30, 2009, we have recognized no ineffective portion of our cash flow hedges. We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our revolving credit facility agreement and the collateral for the outstanding borrowings under our revolving credit facility agreement is used as collateral for our hedges. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our revolving credit facility agreement.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. SFAS 157 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both at June 30, 2009. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

Natural Gas Hedges In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

Interest Rate Swaps In order to estimate the fair value of our interest rate swaps, we use a yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available Money Market rates and Interest Rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

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Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	June 30, 2009		December 31, 2008		June 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under SFAS 133								
Interest rate swaps	Derivative asset (current)	$	Derivative asset (current)	$	Derivative liability (current)	$ 917,060	Derivative liability (current)	$ 714,903
Interest rate swaps	Derivative asset (non-current)	12,107	Derivative asset (non-current)		Derivative liability (non-current)	142,438	Derivative liability (non-current)	374,489
Total derivatives designated as hedging instruments under SFAS 133		$ 12,107		$		$ 1,059,498		$ 1,089,392
Derivatives not designated as hedging instruments under SFAS 133								
Natural gas collar positions	Derivative asset (current)	$ 5,198,878	Derivative asset (current)	$ 6,596,360	Derivative liability (current)	$	Derivative liability (current)	$
Natural gas collar positions	Derivative asset (non-current)		Derivative asset (non-current)	723,669	Derivative liability (non-current)	71,450	Derivative liability (non-current)	
Natural gas swap positions	Derivative asset (current)	234,369	Derivative asset (non-current)		Derivative liability (non-current)		Derivative liability (non-current)	
Total derivatives not designated as hedging instruments under SFAS 133		$ 5,433,247		$ 7,320,029		$ 71,450		$

Note 7 Long-Term Debt

On March 12, 2009, the Company s bank syndicate approved a borrowing base of $140 million after completing its year-end borrowing base determination. The next regular borrowing base determination, which will be based on a June 30, 2009 reserve report prepared by the Company, is scheduled to be complete on or before December 16, 2009. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. Our revolving credit facility permits us to borrow and repay amounts as needed based on the available borrowing base as determined in the revolving credit facility agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the revolving credit facility is based upon the reserve valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year. If not extended, our credit facility will mature in January 2011.

As of June 30, 2009, we had $121.75 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $18.25 million under our $140.00 million borrowing base. For the three and six months ended June 30, 2009 we borrowed $12.05 million and $28.55 million, respectively, and made payments of $11.30 million and $23.30 million, respectively, under the revolving credit facility. For the three and six months ended June 30, 2008 we borrowed $31.00 million and $50.50 million, respectively, and made payments of $32.00 million and $47.00 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at the Company s option of either (a) the bank s adjusted base rate, which is the greatest of (i) the bank s base rate, (ii) the Federal Funds Rate plus 0.5%, or (iii) the one-month LIBOR rate plus 1%, plus a margin of 1.375% to 2.125% based on borrowing base usage, or (b) the adjusted LIBOR rate, plus a margin of 2.25% to 3.00%, based on borrowing base usage. The rates at June 30, 2009 and December 31, 2008, excluding the effect of our interest rate swaps,

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were 3.27% and 2.49%, respectively. For the three months ended June 30, 2009 and 2008, interest on the borrowings averaged 3.55% per annum and 3.59% per annum, respectively. For the six months ended June 30, 2009 and 2008, interest on the borrowings averaged 2.99% per annum and 3.04% per annum, respectively.

The following is a summary of our long-term debt at June 30, 2009 and December 31, 2008:

	June 30, 2009	December 31, 2008
Borrowings under revolving credit facility	$ 121,750,000	$ 116,500,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	112,967	135,972
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	94,190	118,735
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	446,575	475,015
Total debt	122,403,732	117,229,722
Less current maturities included in current liabilities	(118,427)	(111,767)
Total long-term debt	$ 122,285,305	$ 117,117,955

We are subject to certain restrictive financial and non-financial covenants under the revolving credit facility agreement, including a minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability, of 1.0 to 1.0, and a rate of consolidated EBITDA, as defined in the amended revolving credit facility agreement, to interest expense of up to 2.75 to 1.0, both as defined in the revolving credit facility agreement. As of June 30, 2009, we were in compliance with all of the financial covenants in the revolving credit facility agreement.

The fair value of long-term debt at June 30, 2009 and December 31, 2008 was approximately $103,473,539 and $92,485,449, respectively. SFAS 157 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the S&P credit rating of a comparable company to ours and the stated interest rates of the debt instruments included our long-term debt, both at June 30, 2009.

Note 8 Common Stock

At June 30, 2009 and December 31, 2008, there were 39,468,046 and 39,305,152 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. At June 30, 2009 and December 31, 2008, there were 329,410 and 401,075 shares of restricted stock, respectively, included in the aforementioned common stock outstanding. For the three and six months ended June 30, 2009, no common stock was issued upon the exercise of stock options granted under our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. For the three and six months ended June 30, 2009, we issued zero and 166,668 shares, respectively, of common stock to our independent directors, representing 50% of their annual retainer. Additionally, for the three and six months ended June 30, 2009, 3,368 shares of restricted stock were forfeited. On June 15, 2009, 403 shares of common stock were purchased by us from a non-executive employee for the payment of $613 in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled.

For the three and six months ended June 30, 2008, we issued a total of 4,000 shares and 44,337 shares, respectively, of common stock upon the exercise of stock options. In March 2008, we issued 253,806 shares of restricted stock to employees of the Company and 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. The shares of common stock were issued upon the exercise of stock options granted under our 2005 Stock Option Plan. The shares of common stock for our independent directors and the restricted stock were issued pursuant to our 2006 Long-Term Incentive Plan. Additionally, 4,891 shares of restricted stock were forfeited.

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Note 9 Share-Based Awards

As of June 30, 2009, we have two stock-based award plans authorized, which include our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted our 2006 Long-Term Incentive Plan, although we will continue to issue shares of our common stock upon exercise of awards previously granted under the 2005 Stock Option Plan.

Our 2006 Long-Term Incentive Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares are reserved for grant under this plan, of which 2,098,422 remain available for issuance at June 30, 2009. The 2006 Long-Term Incentive Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interests of our employees and independent directors with the interests of our stockholders, and to closely link compensation with our performance. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance-based awards and options issued to directors. Performance-based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Performance-based awards issued to our directors vest immediately.

During the three months ended June 30, 2009, we recorded a compensation expense accrual of $230,702 which was allocated among lease operating expenses ($10,234), general and administrative expenses ($178,446), and capitalized to unevaluated gas properties ($42,022). During the six months ended June 30, 2009, we recorded a compensation expense accrual of $606,839 which was allocated among lease operating expenses ($36,804), general and administrative expenses ($464,310), and capitalized to unevaluated gas properties ($105,725). The future compensation cost of all the outstanding awards is $1,467,726 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.32 years. The significant assumptions used in determining the compensation costs included an expected volatility of 56.10%, risk-free interest rate of 1.25%, an expected term of 4.5 years, forfeiture rates from 5% to 15%, and no expected dividends. For the three and six months ended June 30, 2008, no stock options were granted.

Incentive Stock Options

The table below summarizes incentive stock option activity for the six months ended June 30, 2009:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2008	477,169	$ 8.09		
Granted	606,507	$ 0.72		
Transferred	(12,048)	$ 8.30		
Forfeited	(31,625)	$ 2.13		
Outstanding at June 30, 2009	1,040,003	$ 3.97	5.60	$
Options exercisable at June 30, 2009	254,921	$ 8.27	3.57	$

During the three months ended June 30, 2009, no incentive stock options were granted. During the six months ended June 30, 2009, 606,507 incentive stock options were granted with a weighted average grant-date fair value of $200,147. No incentive stock options were exercised during the three and six months ended June 30, 2009. During the three and six months ended June 30, 2008, no incentive stock options were granted. The total intrinsic values of the 4,000 incentive stock options exercised during the three months ended June 30, 2008 was $62,967. The total intrinsic values of the 44,337 incentive stock options exercised during the six months ended June 30, 2008 was $220,275.

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Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the six months ended June 30, 2009:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2008	1,280,087	$ 3.87		
Granted	114,012	$ 0.72		
Transferred	12,048	$ 8.30		
Forfeited	(1,817)	$ 13.00		
Outstanding at June 30, 2009	1,404,330	$ 3.64	3.52	$
Options exercisable at June 30, 2009	1,158,512	$ 3.34	3.71	$

During the three months ended June 30, 2009, no non-qualified stock options were granted. During the six months ended June 30, 2009, 114,012 non-qualified stock options were granted with a weighted average grant-date fair value of $38,192. During the three and six months ended June 30, 2009, no non-qualified stock options were exercised. During the three and six months ended June 30, 2008, no non-qualified stock options were exercised nor granted.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2009:

	Number of Options	Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2008	401,075	$ 6.60
Forfeited	(3,368)	$ 6.58
Vested	(68,297)	$ 6.86
Non-vested restricted stock at June 30, 2009	329,410	$ 6.54

On March 24, 2009, 48,397 shares of restricted stock vested. The fair value of the shares that vested on that date was $31,458. On June 15, 2009, 19,900 shares of restricted stock vested. The fair value of the shares that vested on that date was $30,049.

Note 10 Commitments and Contingencies

From time to time we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, results of operations or cash flows, if any, will be material.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX s position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we filed an amended petition that restated with specificity our claims against CNX and Island Creek, and added Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as defendants. On June 3, 2009, the Court ruled on the demurrers to our claims that had been filed by CNX. The ruling denied CNX s demurrers with respect to four of our five state-law antitrust claims for monopolization and attempted monopolization. The Court s ruling upheld CNX s demurrers only on one antitrust theory and on the claims under Virginia law for tortious interference. As a result of this ruling, we are proceeding to full discovery and moving towards a trial on the merits, seeking $385.6 million in actual damages, with the possibility for trebling of those damages under the statute, as well as injunctive relief to prevent CNX and the other defendants from continuing these alleged anticompetitive activities. Although we remain open to a commercially reasonable settlement, we intend to pursue discovery and trial in this matter.

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Environmental and Regulatory

As of June 30, 2009, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Note 11 Income Taxes

Our effective tax rate differs from the federal statutory rate primarily due to net operating losses (NOL s) in Canada and certain states from which we are currently unable to benefit, as well as state income taxes. The deferred tax asset related to the Canadian and certain state NOL s are fully reserved because it is more likely than not that we will not use those NOL s to offset existing tax liabilities in future years. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to June 30, 2010. For tax reporting purposes, we have federal and state NOL s of approximately $88.9 million and $4.3 million, respectively, at June 30, 2009 that are available to reduce future taxable income. If not utilized, the federal carryforwards would begin to expire in 2022. Certain immaterial portions of the state NOL s will expire prior to 2022. The Canadian NOL for which the deferred tax asset has been fully reserved at June 30, 2009 is $25.7 million. The Canadian statutory tax rate is 26%. The state NOL for which the deferred tax asset has been fully reserved at June 30, 2009 is $0.6 million.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations
Statement Regarding Forward-Looking Information

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe, anticipate, estimate, expect, intend, and similar express are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2008, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 13, 2009.

Overview

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of June 30, 2009, we control a total of approximately 233,000 net acres of coalbed methane and oil and gas development rights.

We primarily explore for, develop, and produce CBM and non-conventional shallow gas. Our objective is to create the premier non-conventional shallow gas company in North America (emphasizing coalbed methane) while maximizing stockholder value through the efficient investment of capital to increase reserves, production, cash flow and earnings. We believe that substantial expertise and experience is required to develop, produce, and operate coalbed methane and non-conventional shallow gas fields in an efficient manner. We believe that the inherent geologic and production characteristics of coalbed methane and non-conventional shallow gas offer significant operational advantages compared to conventional gas production.

Our ability to successfully leverage our competitive strengths and execute our strategy depends upon many factors and is subject to a variety of risks. For example, our ability to drill on our properties and fund our capital budgets depends, to a large extent, upon our ability to generate cash flow from operations at or above current levels and maintain borrowing capacity at or near current levels under our revolving credit facility, or the availability of future debt and equity financing at attractive prices. Changes in natural gas prices may affect both our cash flows and the value of our proved natural gas reserves or our ability to replace production through drilling activities. Many other factors beyond our control, including a material adverse change in our proved natural gas reserves due to factors other than gas pricing changes, our ability to transport our gas to markets, a change in drilling costs, lower than expected production rates, or a material adverse outcome from lawsuits and other factors may adversely affect our ability to fund our anticipated capital expenditures, pursue property acquisitions, and compete for qualified personnel.

Impact of Current Credit Market Conditions and Decreasing Natural Gas Prices

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued declining or prolonged low natural gas prices may also result in non-compliance with our financial covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. The Company intends to cure any non-compliance with its covenants related to its revolving credit facility if they occur. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

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At June 30, 2009, the carrying value of the Company s gas properties in the U.S. and Canada exceeded the full cost ceiling limitation by $17.2 million, net of tax of $10.3 million, based upon the natural gas prices per Mcf in effect as of the balance sheet date, adjusted for location differentials, which were approximately $4.00 and $3.57, respectively. A decline in prices received for gas sales or an increase in operating costs or reductions in estimated economically recoverable quantities could result in the recognition of an impairment of our gas properties in a future period. Holding all factors constant other than natural gas prices, a 10% and 20% decline in the prices used at June 30, 2009 would have resulted in an additional ceiling test impairment of approximately 18% and 36%, respectively, of our full cost pool.

We believe that we are taking the necessary actions to position ourselves to continue operations in the current credit market environment. We believe we have attributes that are beneficial to operations in today s conditions including $1.22 million in cash, $18.25 million available under our revolving credit facility, premium natural gas pricing due to the geographic location of our properties, natural gas hedges, and long-lived reserves with shallow, almost flat, company-wide annual production decline rates.

Trends

Our business is influenced by trends that affect the natural gas industry. In particular, recent declines in natural gas prices and recent economic trends have adversely effected our business, liquidity, results of operations and financial condition.

Our business is increasingly subject to the adverse recent trends in the global capital markets. The recent events in the credit and stock markets indicate a likelihood of a continuation of the economic weakness in the U.S. economy that began in December 2007. The fears about our banking and credit system may adversely impact investor confidence in us, our banking relationships, and the liquidity and financial condition of third parties with whom we conduct operations.

We expect to face continuing challenges resulting from weakness in the U.S. residential and commercial real estate market and increased mortgage, commercial loan and credit card delinquencies, investor anxiety over the U.S. economy, rating agency downgrades of various financial issuers, unresolved issues with structured investment vehicles, deleveraging of financial institutions and hedge funds and dislocation in the inter-bank market. If significant, continued volatility, changes in interest rates, defaults, market liquidity, declines in equity values, and the strengthening or weakening of foreign currencies against the U.S. dollar, individually or in tandem, could have a material adverse effect on our liquidity, results of operations, financial condition or cash flows through realized losses, and impairments.

We have implemented significant countermeasures in response to the above referenced trend in order to enhance our ability to execute our business strategy. These countermeasures include reducing costs, increasing hedging to reduce exposure to volatile natural gas prices and limiting capital spending. Other steps that could be implemented in light of the current adverse trends include selling assets, entering into joint venture agreements with industry partners to reduce our costs, or alternate forms of financing.

On July 9, 2009, the Company announced that it had engaged a divestment firm to market a 50% non-operated working interest in 147 wells in the eastern portion of its Pond Creek Field in West Virginia. The Company estimates that the 50% working interest in these wells currently represents approximately 20% of the Company s net daily production of natural gas and approximately 10% of its proved reserves at December 31, 2008. Proceeds from a sale will be used to pay down our revolving credit facility. The lost future cash flows from the assets conveyed in the sale should be partially offset by lower interest expense, as well as the future production of our 20 well drilling program in the Pond Creek field.

The natural gas industry is capital intensive. We make, and anticipate that we will continue to make, substantial capital expenditures in the exploration for, development and acquisition of natural gas reserves. Historically, our capital expenditures have been financed primarily with internally generated cash from operations, proceeds from bank borrowings, and industry joint venture arrangements. The continued availability of these capital sources depends upon a number of variables, including proved reserves, production from existing wells, the sales prices for natural gas, our ability to acquire, locate and produce new reserves, and events occurring within the global capital markets. Except for the existing revolving credit facility we have with our bank lenders, we do not currently have any agreements for future financing and there can be no assurance as to the availability or terms of any such future financing.

Operational Developments

Pond Creek We connected 3 new wells to sales in the six months ended June 30, 2009, giving us a total of 245 productive wells in the Pond Creek field. Net gas sales increased to 14.4 MMcf per day for the six months ended June 30, 2009, as compared to 13.4 MMcf per day for the six months ended June 30, 2008. Two new facilities are currently being installed at Pond Creek. First we added a fifth gas-fired compressor at our Pond Creek #1 site that became operational in August. We are also in the installing a reverse osmosis unit in Pond Creek that will reduce the amount of produced water we truck to our disposal well.

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Lasher No new wells were added to sales in the six months ended June 30, 2009. Net gas sales averaged 0.2 MMcf per day from 18 wells for the six months ended June 30, 2009. A pump station was constructed in the second quarter and recently put into operation to pump produced water from a tank battery to the disposal well instead of trucking.

Gurnee No new wells were added to sales in the six months ended June 30, 2009. Net gas sales decreased to 5.9 MMcf per day from a total of 244 productive wells in the Gurnee field for the three months ended June 30, 2009, as compared to 6.0 MMcf per day for the three months ended June 30, 2008. Net gas sales decreased to 6.0 MMcf per day for the six months ended June 30, 2009, as compared to 6.1 MMcf per day for the six months ended June 30, 2008. We have no drilling scheduled in Gurnee in 2009. Also, coal mining activity in the Gurnee field, which has disrupted production and added cost, has ended.

Garden City In this Chattanooga shale prospect, we have drilled four vertical wells and two horizontal wells. The last horizontal well was completed in January 2009 and placed into sales in March 2009. The well has produced at rates in excess of 340 Mcf/day. Two vertical and another horizontal well are currently connected to a gas sales line but the horizontal well is shut-in, awaiting the identification of adequate water disposal. Two additional wells on the west side of the prospect are shut-in and awaiting identification of adequate water disposal and connection into a gas sales line. We are currently evaluating potential water disposal solutions. We are seeking a partner for this project.

Peace River On December 31, 2008, we commenced gas deliveries from eight wells at Peace River with net gas sales averaging 0.1 MMcf per day for the six months ended June 30, 2009. We own a 50% working interest and operate the project which covers over 50,000 acres of Crown tenure. Four coreholes and twelve production wells have been drilled, targeting the Lower Cretaceous Gething coals. Average coal thickness over the acreage is 52 feet, and the average gas content is 400 cubic feet per ton.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires us to use our judgment to make estimates and assumptions that affect certain amounts reported in our financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Critical accounting policies are those accounting policies that involve judgment and uncertainties affecting the application of those policies and the likelihood that materially different amounts would be reported under different conditions or using differing assumptions. We periodically update our estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. There have been no significant changes to our critical accounting policies during the three and six months ended June 30, 2009.

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Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and six months ended June 30, 2009 and 2008. This table should be read in conjunction with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Gas sales	$ 6,838	$ 20,701	$ 16,290	$ 36,282
Lease operating expenses	$ 3,348	$ 3,640	$ 7,917	$ 7,392
Compression and transportation expenses	1,365	1,005	2,815	2,048
Production taxes	241	634	608	1,056
Total production expenses	$ 4,954	$ 5,279	$ 11,340	$ 10,496
Net sales volumes (MMcf)	1,903	1,856	3,790	3,727
Pond Creek field	1,312	1,223	2,603	2,446
Gurnee field	537	550	1,094	1,109
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 3.59	$ 11.15	$ 4.30	$ 9.73
Average natural gas sales price realized(1)	$ 5.03	$ 10.35	$ 5.74	$ 9.57
Lease operating expenses	$ 1.76	$ 1.96	$ 2.09	$ 1.98
Pond Creek field	$ 1.14	$ 1.53	$ 1.44	$ 1.57
Gurnee field	$ 2.74	$ 3.22	$ 2.95	$ 3.20
Compression and transportation expenses	$ 0.72	$ 0.54	$ 0.74	$ 0.55
Pond Creek field	$ 0.72	$ 0.57	$ 0.74	$ 0.61
Gurnee field	$ 0.58	$ 0.56	$ 0.59	$ 0.52
Production taxes	$ 0.13	$ 0.34	$ 0.16	$ 0.29
Pond Creek field	$ 0.10	$ 0.17	$ 0.13	$ 0.12
Gurnee field	$ 0.18	$ 0.66	$ 0.25	$ 0.59
Total production expenses	$ 2.61	$ 2.84	$ 2.99	$ 2.82
Pond Creek field	$ 1.96	$ 2.27	$ 2.31	$ 2.30
Gurnee field	$ 3.50	$ 4.44	$ 3.79	$ 4.31
Depreciation, depletion and amortization	$ 1.04	$ 1.31	$ 1.32	$ 1.31

(1) Average realized price includes the effects of realized (gains) losses on derivative contracts.

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Results of Operations

Three months ended June 30, 2009 compared with three months ended June 30, 2008

The following are selected items derived from our Consolidating Statement of Operations and their percentage changes from the comparable period are presented below.

	Three months ended June 30, 2009	Three months ended June 30, 2008	Change
	(In thousands)		
Gas sales	$ 6,838	$ 20,701	-67%
Lease operating expenses	$ 3,348	$ 3,640	-8%
Compression expense	$ 949	$ 733	29%
Transportation expense	$ 416	$ 272	53%
Production taxes	$ 241	$ 634	-62%
Impairment of gas properties	$ 27,582	$	NM
Depreciation, depletion and amortization	$ 1,982	$ 2,489	-20%
General and administrative	$ 2,181	$ 2,887	-24%
Realized (gains) losses on derivative contracts	$ (2,734)	$ 1,493	NM
Unrealized losses from the change in market value of open derivative contracts	$ 2,144	$ 12,098	-82%
Interest expense, net of amounts capitalized	$ 1,418	$ 1,117	27%
Income tax benefit	$ (11,212)	$ (1,235)	NM

NM-Not Meaningful

Gas sales. Gas sales decreased by $13.86 million, or 67%, to $6.84 million compared to the prior year quarter. The decrease in gas sales was a result of significantly lower natural gas prices partially offset by increased production. Production increased 3% and average natural gas prices decreased 68%, excluding hedging transactions. The $13.86 million decrease in gas sales consisted of a $14.39 million decrease in prices, offset by a $0.53 million increase in production. The increase in production was principally attributable to the prior year development activities at our Pond Creek field.

Lease operating expenses. Lease operating expenses decreased by $0.29 million, or 8%, to $3.35 million compared to the prior year quarter. The decrease in lease operating expenses consisted of a $0.39 million decrease in costs, offset by a $0.10 million increase in production. The $0.39 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009 and a credit for prior period ad valorem taxes, partially offset by increased expenses related to the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River field in December 2008.

Compression expense. Compression expense increased by $0.22 million, or 29%, to $0.95 million compared to the prior year quarter. The $0.22 million increase was comprised of a $0.20 million increase in costs and a $0.02 increase in production. The $0.20 million increase in costs was primarily due to the commencement of gas sales in our Garden City, Lasher, and Peace River fields in 2008 combined with an increase in the rates for electricity used to power compressors at our Pond Creek field, as well as unscheduled repair and maintenance costs.

Transportation expense. Transportation expenses increased by $0.14 million, or 53%, to $0.42 million compared to the prior year quarter. The increase in costs was primarily due to the fact that a greater amount of excess capacity was released in the prior year period effectively reducing transportation expense for that period. The excess transportation capacity that caused the increase was permanently released in May 2009. As a result of this permanent release, we expect to incur less transportation costs in the future.

Production taxes. Production taxes decreased by $0.39 million, or 62%, to $0.24 million compared to the prior year quarter. The $0.39 million decrease in production taxes was primarily due to decreased natural gas sales caused by lower natural gas prices.

Impairment of gas properties. At June 30, 2009, the carrying value of the Company s gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the prior year period.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $0.51 million, or 20%, to $1.98 million compared to the prior year quarter. The depreciation, depletion and amortization decrease consisted of a $0.57 million decrease in the depletion rate due to our ceiling write-downs incurred to-date, partially offset by a $0.06 million increase in production.

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General and administrative. General and administrative expenses decreased by $0.71 million, or 24%, to $2.18 million compared to the prior year quarter. The primary driver of the decrease in general and administrative expenses was our cost reduction strategy, which was implemented in April 2009, partially offset by lower capitalizable overhead as a result of decreased drilling activities.

Realized (gains) losses on derivative contracts. Realized gains on derivative contracts were $2.73 million in the current quarter as compared to realized losses of $1.49 million in the prior year quarter. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts decreased by $9.95 million, or 82%, to $2.14 million compared to the prior year quarter. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.30 million to $1.42 million compared to the prior year quarter. The increase is due to the effect of a higher average outstanding debt balance in the current year period and $0.10 million capitalized interest in the prior year period for which there was no capitalized interest in the current year period, partially offset by a lower average interest rate in the current year period.

Income tax benefit. Income tax benefit was $11.21 million in the current year as compared to a benefit of $1.24 million in the prior year period. The effective tax rate for the period was 36.6% as compared to 28.0% for the prior year period. Both periods were below our statutory tax rate of 38.2% (34% Federal and 4.2% weighted average state) due to the valuation of uncertain portions of our net operating loss carryforwards in both periods.

Six months ended June 30, 2009 compared with six months ended June 30, 2008

The following are selected items derived from our Consolidating Statement of Operations and their percentage changes from the comparable period are presented below.

	Six months ended June 30, 2009	Six months ended June 30, 2008	Change
	(In thousands)		
Gas sales	$ 16,290	$ 36,282	-55%
Lease operating expenses	$ 7,917	$ 7,392	7%
Compression expense	$ 1,782	$ 1,430	25%
Transportation expense	$ 1,033	$ 618	67%
Production taxes	$ 608	$ 1,056	-42%
Impairment of gas properties	$ 167,295	$	NM
Depreciation, depletion and amortization	$ 5,018	$ 4,949	1%
General and administrative	$ 5,154	$ 5,380	-4%
Realized (gains) losses on derivative contracts	$ (5,457)	$ 631	NM
Unrealized losses from the change in market value of open derivative contracts	$ 1,958	$ 20,745	-91%
Interest expense, net of amounts capitalized	$ 2,401	$ 2,420	-1%
Income tax benefit	$ (64,108)	$ (2,469)	NM

NM-Not Meaningful

Gas sales. Gas sales decreased by $19.99 million, or 55%, to $16.29 million compared to the prior year period. The decrease in gas sales was a result of significantly lower natural gas prices partially offset by increased production. Production increased 2% and average natural gas prices decreased 56%, excluding hedging transactions. The $19.99 million decrease in gas sales consisted of a $20.61 million decrease in prices, offset by a $0.62 million increase in production. The increase in production was principally attributable to the prior year development activities at our Pond Creek field.

Lease operating expenses. Lease operating expenses increased by $0.53 million, or 7%, to $7.92 million compared to the prior year period. The increase in lease operating expenses consisted of a $0.41 million increase in costs and a $0.12 million increase in production. The $0.41 increase in costs was primarily due to the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River field in December 2008, offset by a credit for prior period ad valorem taxes. Generally, lease operating expenses are higher in the early life of a prospect.

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Compression expense. Compression expense increased by $0.35 million, or 25%, to $1.78 million compared to the prior year period. The $0.35 million increase was comprised of a $0.33 million increase in costs and a $0.02 increase in production. The $0.33 increase in costs was primarily due to routine maintenance of some of the compressors in our Cahaba field and increased rates for electricity used to power compressors at our Pond Creek field, as well as unscheduled repair and maintenance costs.

Transportation expense. Transportation expenses increased by $0.42 million, or 67%, to $1.03 million compared to the prior year period. The increase in costs was primarily due to the fact that a greater amount of excess capacity was released in the prior year period effectively reducing transportation expense for that period. The excess transportation capacity that caused the increase was permanently released in May 2009. As a result of this permanent release, we expect to incur less transportation costs in the future.

Production taxes. Production taxes decreased by $0.45 million, or 42%, to $0.61 million compared to the prior year period. The $0.45 million decrease in production taxes was primarily due to decreased natural gas sales caused by lower natural gas prices.

Impairment of gas properties. At June 30, 2009, the carrying value of the Company s gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the prior year period.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.07 million, or 1%, to $5.02 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of a $0.08 million increase in production, offset by a $0.01 million decrease in the depletion rate due to our ceiling write-downs incurred to-date.

General and administrative. General and administrative expenses decreased by $0.23 million, or 4%, to $5.15 million compared to the prior year period. The primary driver of the decrease in general and administrative expenses is the cost reduction strategy implemented in April 2009, partially offset by lower capitalizable overhead as a result of decreased drilling activities.

Realized (gains) losses on derivative contracts. Realized gains on derivative contracts were $5.46 million in the current year period as compared to realized losses of $0.63 million in the prior year period. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts decreased by $18.79 million, or 91%, to $1.96 million compared to the prior year quarter. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.02 million to $2.40 million compared to the prior year period. The increase is due to the effect of a higher average outstanding debt balance in the current year period and $0.18 million capitalized interest in the prior year period for which there was no capitalized interest in the current year period, partially offset by a lower average interest rate in the current year period.

Income tax benefit. Income tax benefit was $64.11 million in the current year as compared to a benefit of $2.47 million in the prior year period. The effective tax rate for the period was 37.4% as compared to 31.7% for the prior year period. Both periods were below our statutory tax rate of 38.2% (34% Federal and 4.2% weighted average state) due to the valuation of uncertain portions of our net operating loss carryforwards in both periods.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the six months ended June 30, 2009 and 2008 were $3.2 million and $17.6 million, respectively. Cash flows from operations of $3.2 million for the six months ended June 30, 2009, combined with net cash provided by financing activities of $5.2 million and the use of available cash, were sufficient to fund net cash used in investing activities of $9.3 million, which primarily includes capital expenditures for the exploration and development of our gas properties. Net cash provided by financing activities was related to credit facility net borrowings.

As of June 30, 2009, we had working capital of approximately $1.5 million. As of December 31, 2008, we had a working capital deficit of approximately $1.4 million.

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Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our credit facility and proceeds from potential transactions such as joint ventures, or asset sales will provide the ability to develop our existing properties and conduct exploration.

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued declining or prolonged low natural gas prices may also result in non-compliance with our financial covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

The recent disruption in the credit markets has had a significant adverse impact on a number of financial institutions. We have reviewed the creditworthiness of the banks and financial institutions with which we maintain our cash and short-term investments. Thus far, our liquidity and financial position have not been impacted. However, we cannot predict with any certainty the impact of any further disruption in the credit markets.

Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that natural gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily using derivative instruments in the form of three-way collars, traditional collars and swaps. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu below the bought floor. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments may materially affect our financial position and results of operations as a result of changes in the estimated market value of our natural gas derivatives. Nevertheless, we believe that the use of these instruments will not have a material adverse effect on our cash flows.

Commodity Price Risk and Related Hedging Activities

At June 30, 2009, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
July through October 2009	738,000	(1)	$ 7.50	$ 5.25	$ 1,583,705
July through October 2009	738,000	(1)	$ 8.50	$ 6.50	1,449,387
July through October 2009 (1)	1,476,000	$ 4.50	$ 3.70	(1)	23,172
November 2009 through March 2010	906,000	$ 11.20	$ 9.50	$ 7.00	1,966,202
November 2009 through March 2010	604,000	$ 6.65	$ 5.50	$ 3.50	133,495
April through October 2010	856,000	$ 6.80	$ 5.50	$ 3.50	$ (28,533)

$ 5,127,428

(1) In connection with the July through October 2009 natural gas collar related to natural gas volumes of 1,476,000 MMBtu/day denoted above, the Company eliminated the existing $10.00 sold ceilings with respect to all three-way-collars through October 2009.

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At June 30, 2009, we had the following natural gas swap position:

Period	Volume (MMBtu)	Price	Fair Value
July through October 2009	492,000	$ 4.47	$ 234,369

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At June 30, 2009, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate (1)	Notional amount	Fair Value
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%	$ 15,000,000	$ (575,685)
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%	$ 10,000,000	$ (231,422)
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%	$ 10,000,000	$ (120,248)
Floating-to-fixed swap	5/13/2008	5/13/2010	3.07%	$ 5,000,000	$ (105,103)
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	$ (14,933)
					$ (1,047,391)

(1) The floating rate paid by the counterparty is the British Bankers Association LIBOR rate.

Capital Expenditures and Capital Resources

The following table is a summary of our capital expenditures on an accrual basis by category:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Capital expenditures:				
Leasehold acquisition	$ 315,644	$ 1,006,919	$ 955,617	$ 1,835,486
Exploration	12,270	246,577	21,877	256,635
Development	1,456,141	10,841,920	3,502,076	16,138,356
Other items (primarily capitalized overhead and interest)	450,979	986,535	1,010,310	2,933,227
Total capital expenditures	$ 2,235,034	$ 13,081,951	$ 5,436,653	$ 21,163,704

We expect our capital expenditure budget for 2009 to be funded from our operating cash flows. If the amount or timing of cash flows are reduced, we intend to reduce our capital spending accordingly. The amount and timing of our expenditures are subject to change based upon market conditions, natural gas prices, results of expenditures and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and changes in borrowing capacity under our revolving credit facility. Based on current gas price projections, we expect capital expenditures to be in a range of $14 to $16 million in 2009.

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The development of coalbed methane fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, the transportation alternatives, and the timing and rate of initial and subsequent natural gas production volumes.

Currently, there is an unprecedented uncertainty in the financial markets. The uncertainty in the market brings additional potential risks to us. The risks include less availability and higher costs of additional credit, potential counterparty defaults, and further commercial bank failures. Although the financial institutions in our bank group appear to be capable of meeting their obligation under the facility, some that have been and others could be considered take-over candidates. Although we have no indication that any such transactions would impact our current credit facility, the possibility exists. Financial market disruptions may impact our ability to collect trade receivables. We constantly monitor the credit worthiness of our customers. We believe that our current group of counterparties are sound and represent no abnormal business risk.

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued or prolonged low natural gas prices may also result in non-compliance with our financial covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

Revolving Credit Facility

On March 12, 2009, the Company s bank syndicate approved a borrowing base of $140 million after completing its year-end borrowing base determination. The next regular borrowing base determination, which will be based on a June 30, 2009 reserve report prepared by the Company, is scheduled to be complete on or before December 16, 2009. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. Our revolving credit facility permits us to borrow and repay amounts as needed based on the available borrowing base as determined in the revolving credit facility agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the revolving credit facility is based upon the reserve valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year. If not extended, our credit facility will mature in January 2011.

As of June 30, 2009, we had $121.75 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $18.25 million under our $140.0 million borrowing base. For the three and six months ended June 30, 2009 we borrowed $12.05 million and $28.55 million, respectively, and made payments of $11.30 million and $23.30 million, respectively, under the revolving credit facility. For the three and six months ended June 30, 2008 we borrowed $31.00 million and $50.50 million, respectively, and made payments of $32.00 million and $47.00 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at the Company s option of either (a) the bank s adjusted base rate, which is the greatest of (i) the bank s base rate, (ii) the Federal Funds Rate plus 0.5%, or (iii) the one-month LIBOR rate plus 1%, plus a margin of 1.375% to 2.125% based on borrowing base usage, or (b) the adjusted LIBOR rate, plus a margin of 2.25% to 3.00%, based on borrowing base usage. The rates at June 30, 2009 and December 31, 2008, excluding the effect of our interest rate swaps, were 3.27% and 2.49%, respectively. For the three months ended June 30, 2009 and 2008, interest on the borrowings averaged 3.55% per annum and 3.59% per annum, respectively. For the six months ended June 30, 2009 and 2008, interest on the borrowings averaged 2.99% per annum and 3.04% per annum, respectively.

We are subject to certain restrictive financial and non-financial covenants under the revolving credit facility agreement, including a minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability, of 1.0 to 1.0, and a ratio of consolidated EBITDA, as defined in the amended revolving credit facility agreement, to interest expense of up to 2.75 to 1.0, both as defined in the revolving credit facility agreement. As of June 30, 2009, we were in compliance with all of the financial covenants in the revolving credit facility agreement.

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Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments.

Recent Pronouncements

FASB Accounting Standards Codification In June 2009, the FASB issued the FASB Accounting Standards Codification (Codification). The Codification will become the single source for all authoritative GAAP recognized by the FASB to be applied for financial statements issued for periods ending after September 15, 2009. The Codification does not change GAAP and will not affect our financial position, results of operations or liquidity.

SFAS No. 165, Subsequent Events In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*. The standard does not require significant changes regarding recognition or disclosure of subsequent events, but does require disclosure of the date through which subsequent events have been evaluated for disclosure and recognition. The standard is effective for financial statements issued after June 15, 2009. The implementation of this standard did not have a significant impact on the financial statements of the Company. Subsequent events through the filing date of this Quarterly Report on Form 10-Q have been evaluated for disclosure and recognition.

Recent FASB Staff Positions On July 1, 2009, we adopted three FASB Staff Positions (FSP) effective for interim and annual periods ending after June 15, 2009 as follows:

(1) Determining Fair Value When Market Activity Has Decreased FSP FAS 157-4, which applies to all assets and liabilities (i.e., financial and nonfinancial), reemphasizes that the objective of fair value remains unchanged (i.e., an exit price notion). FSP FAS 157-4 provides application guidance on measuring fair value when the volume and level of activity has significantly decreased and identifying transactions that are not orderly. FSP FAS 157-4 also emphasizes that an entity cannot presume that an observable transaction price is not orderly even when there has been a significant decline in the volume and level of activity. FSP FAS 157-4 also requires enhanced disclosures.

(2) Other-Than-Temporary Impairment (OTTI) FSP FAS 115-2/124-2 provides a new OTTI model for debt securities only. Equity securities will continue to apply the existing OTTI model. The FSP shifts the focus for debt securities from an entity s intent to hold until recovery to its intent to sell. FSP FAS 115-2/124-2 also requires entities to initially apply the provisions of the standard to certain previously other-than-temporarily impaired debt instruments existing as of the date of initial adoption by making a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The cumulative-effect adjustment reclassifies the noncredit portion of a previously other-than-temporarily impaired debt security held as of the date of initial adoption from retained earnings to accumulated other comprehensive income. FSP FAS 115-2/124-2 also requires enhanced disclosures.

(3) Interim Fair Value Disclosures for Financial Instruments FSP FAS 107-1/APB 28-1 expands the fair value disclosures required for all financial instruments within the scope of Statement 107 to interim periods. The disclosure requirements of FSP FAS 107-1/APB 28-1 only apply to public entities. FSP FAS 107-1/APB 28-1 does not require interim disclosures of credit or market risks also discussed in Statement 107.

The adoption of the aforementioned three FASB Staff Positions had no material impact on Consolidated Financial Statements (Unaudited) or the accompanying Notes to Consolidated Financial Statements (Unaudited).

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

Commodity Prices Economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used.

Disclosure of Unproved Reserves Probable and possible reserves may be disclosed separately on a voluntary basis.

Proved Undeveloped Reserve Guidelines Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.

Reserve Estimation Using New Technologies Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Reserve Personnel and Estimation Process Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

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Non-Traditional Resources The definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. We are currently evaluating the new rules and assessing the impact they will have on our reported proved natural gas reserves. The SEC is coordinating with the Financial Accounting Standards Board to obtain the revisions necessary to SFAS 19, Financial Accounting and Reporting by Oil and Gas Producing Companies , and SFAS 69 to provide consistency with the new rules.

In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC will consider delaying the compliance date.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are natural gas prices per Mcf in effect, adjusted for location differentials. Prices received for natural gas are volatile and unpredictable and are beyond our control. At June 30, 2009, a 10% decrease in the prices received for natural gas production would have had an approximate $1.2 million impact on our revenues.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. At June 30, 2009, we had $121.75 million outstanding under our revolving credit facility. At June 30, 2009 the average interest rate for the outstanding amount of the revolving credit facility was 3.27% per annum, respectively. Borrowing availability at June 30, 2009 was $18.25 million. All of the debt outstanding under our revolving credit facility accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance outstanding under our revolving credit facility at June 30, 2009, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.8 million. $45 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swaps we have in place.

Foreign Currency Exchange Rate Risk. We have operations in Canada and do not have operations in any other foreign countries. We do not hedge our foreign currency risk and are exposed to foreign currency exchange rate risk in the Canadian dollar. Because our cash flows from our Canadian project are not material, changes in the exchange rate do not significantly impact our revenues or expenses but primarily affect the costs of unevaluated properties. We continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15(e) and 15d-15(e), we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2009 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, results of operations or cash flows, if any, will be material.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX s position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we filed an amended petition that restated with specificity our claims against CNX and Island Creek, and added Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as defendants. On June 3, 2009, the Court ruled on the demurrers to our claims that had been filed by CNX. The ruling denied CNX s demurrers with respect to four of our five state-law antitrust claims for monopolization and attempted monopolization. The Court s ruling upheld CNX s demurrers only on one antitrust theory and on the claims under Virginia law for tortious interference. As a result of this ruling, we are proceeding to full discovery and moving towards a trial on the merits, seeking $385.6 million in actual damages, with the possibility for trebling of those damages under the statute, as well as injunctive relief to prevent CNX and the other defendants from continuing these alleged anticompetitive activities. Although we remain open to a commercially reasonable settlement, we intend to pursue discovery and trial in this matter.

Environmental and Regulatory

As of June 30, 2009, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 1A. Risk Factors

There has been the following change from the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2008:

We may not be able to maintain compliance with NASDAQ s continued listing requirements.

We must comply with NASDAQ s continued listing requirements in order to maintain our listing on NASDAQ s Global Market. These continued listing standards include requirements addressing the number of shares publicly held, market value of publicly held shares, stockholder s equity, number of round lot holders, and a $1.00 minimum closing bid price. Our stock price has traded below the $1.00 minimum bid price from time to time since March 2009. If a company s closing bid price is below $1.00 for 30 consecutive trading days, it receives a notice from NASDAQ that it will be subject to delisting if it fails to regain compliance within 180 days following the date of the notice letter by maintaining a minimum bid closing price of at least $1.00 for ten consecutive business days. If NASDAQ reinstates the $1.00 minimum bid price requirement as scheduled and, thereafter, the closing bid price for our common stock is below $1.00 per share for 30 consecutive days or if we in the future fail to meet the other requirements for continued listing on the NASDAQ Global Market, then our common stock could be delisted. On August 7, 2009, the Company s stock closed at a bid price of $1.22.

In order to regain compliance with the $1.00 minimum bid requirement, we would have to attain a stock price of at least $1.00 per share for a minimum of 10 consecutive business days prior to the expiration of 180 days from the date of the notice letter from NASDAQ, but the NASDAQ may in its discretion require that we maintain a bid price of at least $1.00 per share for a period in excess of 10 consecutive business days.

The delisting of our common stock would adversely affect the market liquidity for our common stock, the per share price of our common stock and impair our ability to raise capital that may be needed for future operations. Delisting from NASDAQ could also have other negative results, including the potential loss of confidence by customers and employees, the loss of institutional investor interest and fewer business development opportunities. In addition, we would be subject to a number of restrictions regarding the registration and qualification of our common stock under federal and state securities laws.

If our common stock is not eligible for quotation on another market or exchange, trading of our common stock could be conducted in the over-the-counter market or on an electronic bulletin board established for unlisted securities such as the Pink Sheets or the OTC Bulletin Board. In such event, it could become more difficult to dispose of, or obtain accurate quotations for the price of our common stock, and there would likely also be a reduction in our coverage by security analysts and the news media, which could cause the price of our common stock to decline further.

If our stock price trades below $1.00 for a sustained period and we face delisting on the NASDAQ, we may seek to implement a reverse stock split. However, reverse stock splits frequently result in a loss in stockholder value as the actual post-split price is often lower than the pre-split price, adjusted for the split. Accordingly, a reverse stock split may not solve the listing requirement deficiency even if implemented.

Federal climate change regulation could increase our operating and capital costs.

The American Clean Energy and Security Act of 2009 (ACES), also known as the Waxman-Markey Bill, was approved by the House of Representatives on June 26, 2009. The ACES, if passed by the Senate, would establish a variant of a cap-and-trade plan for greenhouse gases (GHG) in order to address climate change. A cap-and-trade plan would require businesses that emit more greenhouse gases than permitted to acquire emission allowances from other businesses that emit greenhouse gases at levels lower than the limits specified and then surrender these allowances as a credit against such emissions. As a result of such a plan, we could be required to purchase and surrender emission allowances for GHG emissions resulting from our operations.

Although it is not possible at this time to predict the final outcome of the ACES, any new federal restrictions on GHG emissions, including a cap-and-trade-plan, that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on our business or demand for the natural gas we produce.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACES contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACES would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACES, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as natural gas. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACES, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our natural gas positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills,

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if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

Period		Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
04/01/09	04/30/09				
05/01/09	05/31/09				
06/01/09	06/30/09	406	$ 1.51		

(1) Stock repurchases during the period related to stock received by us from certain non-executive employees for the payment of withholding taxes due on vested shares of restricted stock issued under stock-based compensation plans.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

Our annual meeting of stockholders was held on May 8, 2009 in Houston, Texas for the purpose of voting on two proposals.

1. The first of those proposals related to the election of individuals to serve as directors of GeoMet until the next annual meeting of the GeoMet s stockholders. The seven directors elected and the tabulation of votes (both in person and by proxy) was as follows:

Nominees for Director	Votes For	Witheld
J. Darby Seré	36,100,711	615,924
J. Hord Armstrong, III	35,977,719	738,916
James C. Crain	35,811,363	905,272
Stanley L. Graves	36,083,833	632,802
Charles D. Haynes	36,106,303	610,332
W. Howard Keenan, Jr.	35,976,021	740,614
Philip G. Malone	35,229,266	1,487,369

2. To ratify approve an amendment to the GeoMet 2006 Long Term Incentive Plan to increase the number of shares of common stock authorized for issuance under the plan from 2,000,000 to 4,000,000, which was ratified and approved:

For	Against	Abstain	Broker Non-Votes
30,102,482	3,977,328	3,190	2,633,635

Item 5. Other Information

None.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

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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.

	GeoMet, Inc.
Date: August 7, 2009	By /s/ William C. Rankin William C. Rankin, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS

Exhibit Number	Exhibits
10.1	GeoMet, Inc. 2006 Long-Term Incentive Plan (Amended and Restated Effective March 12, 2009) (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on May 13, 2009)
31.1*	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32*	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).

* Attached hereto