
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549**

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2010

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
(State or other jurisdiction of
incorporation or organization)

76-0662382
(I.R.S. Employer
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. 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

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 No

As of April 21, 2010, there were 39,401,508 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)**

	<u>March 31,</u> <u>2010</u>	<u>December 31,</u> <u>2009</u>
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 1,061,764	\$ 973,720
Accounts receivable, both amounts net of allowance of \$60,848	3,026,539	2,909,293
Inventory	1,640,204	2,131,901
Derivative asset	8,853,181	2,563,898
Other current assets	333,106	475,025
Total current assets	<u>14,914,794</u>	<u>9,053,837</u>
Gas properties—utilizing the full cost method of accounting:		
Proved gas properties	463,560,968	461,003,091
Other property and equipment	3,376,622	3,480,202
Total property and equipment	466,937,590	464,483,293
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(368,164,749)	(365,784,964)
Property and equipment—net	<u>98,772,841</u>	<u>98,698,329</u>
Other noncurrent assets:		
Derivative asset	2,113,563	761,192
Deferred income taxes	49,858,107	51,804,971
Other	1,344,837	609,972
Total other noncurrent assets	<u>53,316,507</u>	<u>53,176,135</u>
TOTAL ASSETS	<u><u>\$ 167,004,142</u></u>	<u><u>\$ 160,928,301</u></u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	\$ 4,643,069	\$ 5,169,174
Accrued liabilities	3,197,430	2,808,227
Deferred income taxes	2,661,516	157,256
Derivative liability	453,715	724,253
Asset retirement liability	105,251	108,111
Current portion of long-term debt	127,266	121,792
Total current liabilities	<u>11,188,247</u>	<u>9,088,813</u>
Long-term debt	117,626,960	119,996,163
Asset retirement liability	4,997,144	4,862,278
Other long-term accrued liabilities	65,163	73,308
TOTAL LIABILITIES	<u>133,877,514</u>	<u>134,020,562</u>
Commitments and contingencies (Note 15)		
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 39,393,566 and 39,460,060 at March 31, 2010 and December 31, 2009, respectively	39,217	39,294
Treasury stock—10,432 shares at March 31, 2010 and December 31, 2009	(94,424)	(94,424)
Paid-in capital	189,700,606	189,681,816
Accumulated other comprehensive loss	(1,592,735)	(1,768,521)
Retained deficit	(154,683,737)	(160,710,889)
Less notes receivable	(242,299)	(239,537)
Total stockholders' equity	<u>33,126,628</u>	<u>26,907,739</u>
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	<u><u>\$ 167,004,142</u></u>	<u><u>\$ 160,928,301</u></u>

See accompanying Notes to Consolidated Financial Statements (Unaudited)

GEOMET, INC. AND SUBSIDIARIES
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended March 31,	
	2010	2009
Revenues:		
Gas sales	\$ 9,883,686	\$ 9,452,509
Operating fees	74,292	98,011
Total revenues	9,957,978	9,550,520
Expenses:		
Lease operating expense	3,107,371	4,569,317
Compression and transportation expense	1,004,447	1,450,124
Production taxes	208,229	367,062
Depreciation, depletion and amortization	1,645,365	3,036,731
Impairment of gas properties	—	139,712,471
General and administrative	1,477,725	2,972,612
Realized gains on derivative contracts	(1,460,128)	(2,723,304)
Unrealized gains from the change in market value of open derivative contracts	(7,642,042)	(185,883)
Total operating (gains) expenses	(1,659,033)	149,199,130
Operating income (loss)	11,617,011	(139,648,610)
Other income (expense):		
Interest income	25,804	9,960
Interest expense (net of amounts capitalized)	(1,244,160)	(983,045)
Other	(17,327)	(1,018)
Total other income (expense)	(1,235,683)	(974,103)
Income (loss) before income taxes	10,381,328	(140,622,713)
Income tax expense (benefit)	4,354,176	(52,896,909)
Net income (loss)	\$ 6,027,152	\$ (87,725,804)
Income (loss) per share:		
Net income (loss)		
Basic	\$ 0.15	\$ (2.25)
Diluted	\$ 0.15	\$ (2.25)
Weighted average number of common shares:		
Basic	39,158,985	38,923,572
Diluted	39,236,844	38,923,572

See accompanying Notes to Consolidated Financial Statements (Unaudited)

GEOMET, INC. AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
(Unaudited)

	Three Months Ended March 31,	
	2010	2009
Net income (loss).....	\$ 6,027,152	\$ (87,725,804)
Gain on foreign currency translation adjustment	8,833	95,393
Gain (loss) on interest rate swap, net of tax	166,953	(939)
Other comprehensive income (loss).....	\$ 6,202,938	\$ (87,631,350)

See accompanying Notes to Consolidated Financial Statements (Unaudited)

GEOMET, INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended March 31,	
	2010	2009
Cash flows provided by operating activities:		
Net income (loss).....	\$ 6,027,152	\$ (87,725,804)
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation, depletion and amortization.....	1,645,365	3,036,731
Impairment of gas properties.....	—	139,712,471
Amortization of debt issuance costs.....	73,227	42,495
Deferred income tax expense (benefit).....	4,347,926	(52,903,159)
Unrealized gains from the change in market value of open derivative contracts	(7,642,042)	(185,883)
Stock-based compensation	(10,162)	312,433
Loss on sale of other assets	19,498	31,152
Accretion expense	120,486	107,413
Changes in operating assets and liabilities:		
Accounts receivable.....	(114,554)	2,415,286
Inventory.....	497,360	122,099
Other current assets.....	141,919	161,350
Accounts payable.....	(742,624)	(2,517,885)
Other accrued liabilities	372,404	(416,171)
Net cash provided by operating activities	4,735,955	2,192,528
Cash flows used in investing activities:		
Capital expenditures.....	(1,521,283)	(7,041,411)
Proceeds from sale of other property and equipment.....	79,370	18,548
Other assets	25,338	(107,915)
Net cash used in investing activities	(1,416,575)	(7,130,778)
Cash flows provided by financing activities:		
Proceeds from revolver borrowings.....	5,800,000	16,500,000
Payments on revolver.....	(8,100,000)	(12,000,000)
Deferred financing costs	(887,378)	—
Payments on other debt.....	(63,729)	(58,694)
Net cash (used in) provided by financing activities	(3,251,107)	4,441,306
Effect of exchange rate changes on cash.....	19,771	(55,928)
Increase (decrease) in cash and cash equivalents.....	88,044	(552,872)
Cash and cash equivalents at beginning of period	973,720	2,096,561
Cash and cash equivalents at end of period	<u>\$ 1,061,764</u>	<u>\$ 1,543,689</u>
Significant noncash investing and financing activities:		
Accrued capital expenditures.....	<u>\$ 616,093</u>	<u>\$ 1,409,739</u>

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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 (coalbed 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, 2009 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 31, 2010.

Note 2 — Recent Pronouncements

In January 2010, the FASB issued Update No. 2010-06—Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This Update provides amendments to Subtopic 820-10 that require new disclosures for transfers in and out of Levels 1 and 2. This Update also clarifies existing disclosures for level of disaggregation, as well as valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009. See additional disclosure provided in Note 6 — Derivative Instruments and Hedging Activities.

Note 3 — Income (Loss) Per Share

Income (Loss) Per Share of Common Stock – Basic income (loss) per share is calculated by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. Fully diluted income (loss) per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income (loss) by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive income (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 March 31,	
	2010	2009
Net income (loss) per share:		
Basic-net income (loss) per share.....	\$ 0.15	\$ (2.25)
Diluted-net income (loss) per share.....	\$ 0.15	\$ (2.25)
Numerator:		
Net income (loss) available to common stockholders.....	\$ 6,027,152	\$ (87,725,804)
Denominator:		
Weighted average shares outstanding-basic.....	39,158,985	38,923,572
Add potentially dilutive securities:		
Stock options.....	77,859	—
Dilutive securities.....	39,236,844	38,923,572

Diluted net loss per share for the three months ended March 31, 2009 excluded the effect of outstanding options to purchase 2,459,131 shares and 352,678 restricted 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 this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into United States of America (“U.S.”) and Canadian cost centers. The Canadian cost center was fully impaired in 2009.

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 gas reserves. Depletion for the three months ended March 31, 2010 and 2009 was \$0.83 and \$1.52 per Mcf, respectively.

Estimation of proved gas reserves relies on professional judgment and 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 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 estimated future net revenues, discounted at 10% per annum, plus cost of properties not being amortized plus the lower of cost or fair value of unevaluated properties less income tax effects (the “ceiling limitation”). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling test is performed 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 test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions, as allowed by the guidelines of the SEC. In addition, subsequent to the adoption of Accounting Standards Codification (“ASC”) 410-20-25, formerly Financial Accounting Standard Board (“FASB”) Statement No. 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations were not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

No impairments were recorded during the three months ended March 31, 2010.

At March 31, 2009, the ceiling limitation test was calculated using natural gas prices in effect as of the balance sheet date and adjusted for “basis” or location differential, held constant over the life of the reserves; however, as allowed by the guidelines of the SEC in effect at the time, significant changes in gas prices subsequent to quarter end were used in the ceiling limitation test. At March 31, 2009, the carrying value of the Company’s gas properties in the U.S. and Canada exceeded the full cost ceiling limitation by \$112.9 million, net of income tax of \$68.5 million, based upon a natural gas price of approximately \$3.73 per Mcf in effect at that date. However, as allowed by the guidelines of the SEC, since gas prices significantly increased subsequent to March 31, 2009, a recalculation of the ceiling limitation was performed. Based upon a natural gas price of approximately \$4.21 per Mcf in effect at May 7, 2009, the following impairments were recorded as of March 31, 2009 to our gas properties:

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
Impairment of gas properties	\$ 138,371,631	\$ 1,340,840	\$ 139,712,471
Deferred income tax benefit	(52,858,029)	—	(52,858,029)
Impairment of gas properties, net of tax	<u>\$ 85,513,602</u>	<u>\$ 1,340,840</u>	<u>\$ 86,854,442</u>

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 by an assumed inflation factor up to the estimated settlement date, 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 three months ended March 31, 2010:

Current portion of liability at January 1, 2010.....	\$ 108,111
Add: Long-term asset retirement liability at January 1, 2010.....	<u>4,862,278</u>
Asset retirement liability at January 1, 2010	4,970,389
Liabilities incurred.....	6,725
Liabilities settled.....	(3,792)
Accretion	120,486
Foreign currency translation	<u>8,587</u>
Asset retirement liability at March 31, 2010	5,102,395
Less: Current portion of liability	<u>(105,251)</u>
Long-term asset retirement liability.....	<u>\$ 4,997,144</u>

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 70% 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.

Commodity Price Risk and Related Hedging Activities

At March 31, 2010, we had the following natural gas collar positions:

<u>Period</u>	<u>Volume (MMBtu)</u>	<u>Sold Ceiling</u>	<u>Bought Floor</u>	<u>Sold Floor</u>	<u>Fair Value</u>
April through October 2010.....	856,000	\$ 6.80	\$ 5.50	\$ 3.50	\$ 1,172,051
April through October 2010.....	856,000	\$ 6.35	\$ 5.50	—	1,258,999
November 2010 through March 2011	604,000	\$ 7.45	\$ 6.50	—	862,572
	<u>2,316,000</u>				<u>\$ 3,293,622</u>

At December 31, 2009, we had the following natural gas collar positions:

<u>Period</u>	<u>Volume (MMBtu)</u>	<u>Sold Ceiling</u>	<u>Bought Floor</u>	<u>Sold Floor</u>	<u>Fair Value</u>
January 2010 through March 2010	540,000	\$ 11.20	\$ 9.50	\$ 7.00	\$ 1,326,724
January 2010 through March 2010	360,000	\$ 6.65	\$ 5.50	\$ 3.50	65,098
April through October 2010.....	856,000	\$ 6.80	\$ 5.50	\$ 3.50	172,072
April through October 2010.....	856,000	\$ 6.35	\$ 5.50	—	116,559
November 2010 through March 2011	604,000	\$ 7.45	\$ 6.50	—	160,745
	<u>3,216,000</u>				<u>\$ 1,841,198</u>

At March 31, 2010, we had the following natural gas swap positions:

<u>Period</u>	<u>Volume (MMBtu)</u>	<u>Price</u>	<u>Fair Value</u>
April through October 2010.....	856,000	\$ 5.70	\$ 1,389,451
April through October 2010.....	642,000	\$ 6.30	1,426,463
November 2010 through March 2011.....	604,000	\$ 6.67	883,023
November 2010 through March 2011.....	906,000	\$ 7.27	1,860,622
April 2011 through October 2011.....	856,000	\$ 6.37	984,468
April 2011 through October 2011.....	856,000	\$ 5.37	137,364
November 2011 through March 2012.....	608,000	\$ 7.12	688,527
November 2011 through March 2012.....	608,000	\$ 6.12	93,758
April 2012 through October 2012.....	856,000	\$ 5.73	128,447
November 2012 through March 2013.....	604,000	\$ 6.42	80,999
	<u>7,396,000</u>		<u>\$ 7,673,122</u>

At December 31, 2009, we had the following natural gas swap positions:

<u>Period</u>	<u>Volume (MMBtu)</u>	<u>Price</u>	<u>Fair Value</u>
April through October 2010.....	856,000	\$ 5.70	\$ 5,341
April through October 2010.....	642,000	\$ 6.30	387,383
November 2010 through March 2011.....	604,000	\$ 6.67	61,493
November 2010 through March 2011.....	906,000	\$ 7.27	625,564
April 2011 through October 2011.....	856,000	\$ 6.37	236,887
November 2011 through March 2012.....	608,000	\$ 7.12	166,836
	<u>4,472,000</u>		<u>\$ 1,483,504</u>

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 ASC 815-20-25. 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 March 31, 2010, we had the following interest rate swaps:

<u>Description</u>	<u>Effective date</u>	<u>Designated maturity date</u>	<u>Fixed rate (1)</u>	<u>Notional amount</u>	<u>Fair Value</u>
Floating-to-fixed swap.....	12/14/2007	12/14/2010	3.86%	\$ 15,000,000	\$ (382,728)
Floating-to-fixed swap.....	5/13/2008	5/13/2010	3.07%	\$ 5,000,000	(33,033)
Floating-to-fixed swap.....	1/6/2009	1/6/2011	1.38%	\$ 5,000,000	(37,954)
				<u>\$ 25,000,000</u>	<u>\$ (453,715)</u>

At December 31, 2009, we had the following interest rate swaps:

<u>Description</u>	<u>Effective date</u>	<u>Designated maturity date</u>	<u>Fixed rate (1)</u>	<u>Notional amount</u>	<u>Fair Value</u>
Floating-to-fixed swap.....	12/14/2007	12/14/2010	3.86%	\$ 15,000,000	\$ (479,566)
Floating-to-fixed swap.....	1/3/2008	1/4/2010	3.95%	\$ 10,000,000	(87,493)
Floating-to-fixed swap.....	3/25/2008	3/25/2010	2.38%	\$ 10,000,000	(50,745)
Floating-to-fixed swap.....	5/13/2008	5/13/2010	3.07%	\$ 5,000,000	(67,783)
Floating-to-fixed swap.....	1/6/2009	1/6/2011	1.38%	\$ 5,000,000	(38,278)
				<u>\$ 45,000,000</u>	<u>\$ (723,865)</u>

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

For the three months ended March 31, 2010 and 2009, we 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 ASC 820-10-55, formerly SFAS No. 157, Fair Value Measurements, currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, 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. ASC 820-10-55 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 December 31, 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.

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the three months ended March 31, 2010. Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	March 31, 2010		December 31, 2009		March 31, 2010		December 31, 2009	
	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 ASC 815-20-25								
Interest rate swaps.....	Derivative asset (current)	\$ —	Derivative asset (current)	\$ —	Derivative liability (current)	\$453,715	Derivative liability (current)	\$724,253
Interest rate swaps.....	Derivative asset (non-current)	—	Derivative asset (non-current)	388	Derivative liability (non-current)	—	Derivative liability (non-current)	—
Total derivatives designated as hedging instruments under ASC 815-20-25.....		<u>\$ —</u>		<u>\$ 388</u>		<u>\$453,715</u>		<u>\$724,253</u>
Derivatives not designated as hedging instruments under ASC 815-20-25								
Natural gas hedge positions	Derivative asset (current)	\$ 8,853,181	Derivative asset (current)	\$2,563,898	Derivative liability (current)	\$ —	Derivative liability (current)	\$ —
Natural gas hedge positions	Derivative asset (non-current)	2,113,563	Derivative asset (non-current)	760,804	Derivative liability (non-current)	—	Derivative liability (non-current)	—
Total derivatives not designated as hedging instruments under ASC 815-20-25.....		<u>\$10,966,744</u>		<u>\$3,324,702</u>		<u>\$ —</u>		<u>\$ —</u>

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

The Effect of Derivative Instruments on the Consolidated Statements of Operations and Other Comprehensive Income for the Three Months Ended March 31, 2010 and 2009

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative	
		2010	2009
Derivatives designated as hedging instruments under ASC 815-20-25			
Interest rate swaps.....	Interest expense (net of amounts capitalized)	\$ (239,214)	\$ 209,240
Total gain (loss)		<u>\$ (239,214)</u>	<u>\$ 209,240</u>
Derivatives not designated as hedging instruments under ASC 815-20-25			
Natural gas collar positions.....	Realized gains on derivative contracts	\$ (1,460,128)	\$ (2,723,304)
Natural gas collar positions.....	Unrealized (gains) losses from the change in market value of open derivative contracts	<u>(7,642,042)</u>	<u>(185,883)</u>
Total gain (loss)		<u>\$ (9,102,170)</u>	<u>\$ (2,909,187)</u>

Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	
	2010	2009		2010	2009
Interest rate contracts	\$ (30,937)	\$ (216,202)	Interest expense	\$ 239,214	\$ (209,240)
Total.....	<u>\$ (30,937)</u>	<u>\$ (216,202)</u>		<u>\$ 239,214</u>	<u>\$ (209,240)</u>

Accumulated comprehensive loss of \$1,592,735 as of March 31, 2010 consists of \$1,312,339 in foreign currency translation adjustments and a \$280,396 loss on interest rate swaps, net of income tax benefit. Accumulated comprehensive loss of \$280,396 as of March 31, 2010 is expected to be realized as interest expense in the statement of operations for the 12 months ended March 31, 2011.

Note 7 — Long-Term Debt

After the Company received commitment letters from two parties to provide additional financing for the Company, effective March 30, 2010, the parties to the revolving credit facility agreement unanimously approved the Third Amendment to the revolving credit facility (“Third Amendment”) as summarized below:

- The maturity date of the revolving credit facility was extended four months to May 6, 2011 pursuant to a request by the Company.
- Pursuant to a request by the Company, the borrowing base was reduced to \$123 million and the bank group agreed that (1) the next borrowing base determination would be as of June 15, 2010, and (2) the bank group agreed not to call for a determination of the borrowing base prior to that date.
- The minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability under the revolving credit agreement, is adjusted to .80 to 1 solely for the quarter ended March 31, 2010.
- 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 2.625%, or (b) the adjusted LIBOR rate, plus a margin of 3.50%.

As part of the completion of the Third Amendment, the Company was required to pay a non-refundable fee to its bank group in the amount of \$307,500.

As of March 31, 2010, we had \$117.2 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of \$5.8 million under our \$123.0 million borrowing base. For the three months ended March 31, 2010 we borrowed \$5.8 million and made payments of \$8.1 million under the revolving credit facility. For the three months ended March 31, 2009, we borrowed \$16.5 million and made payments of \$12.0 million under the revolving credit facility. The rates at March 31, 2010 and December 31, 2009, excluding the effect of our interest rate swaps, were 3.77% and 3.03%, respectively. For the three months ended March 31, 2010 and 2009, interest on the borrowings averaged 3.14% per annum and 3.31% per annum, respectively.

The following is a summary of our long-term debt at March 31, 2010 and December 31, 2009:

	<u>March 31, 2010</u>	<u>December 31, 2009</u>
Borrowings under revolving credit facility	\$ 117,200,000	\$ 119,500,000
Note payable to a third party, annual installments of \$53,000 through January 2011, interest-bearing at 8.25% annually, unsecured.....	48,961	94,190
Note payable to an individual, semi-monthly installments of \$644, through September 2015, interest-bearing at 12.6% annually, unsecured	103,607	106,825
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	<u>401,658</u>	<u>416,940</u>
Total debt	117,754,226	120,117,955
Less current maturities included in current liabilities	<u>(127,266)</u>	<u>(121,792)</u>
Total long-term debt.....	<u>\$ 117,626,960</u>	<u>\$ 119,996,163</u>

The fair value of long-term debt at March 31, 2010 and December 31, 2009 was approximately \$115,048,602 and \$115,817,126, respectively. ASC 820-10-55 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 March 31, 2010 and December 31, 2009.

Note 8 — Common Stock

At March 31, 2010 and December 31, 2009, there were 39,393,566 and 39,460,060 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. Also included in common stock outstanding at March 31, 2010 and December 31, 2009 were 176,128 and 311,684 shares of restricted stock, respectively. For the three months ended March 31, 2010, 66,194 shares of restricted stock were forfeited. On March 24, 2010, 300 shares of common stock were purchased by us from a non-executive employee for the payment of \$289 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 months ended March 31, 2009, we issued 166,668 shares of common stock to our independent directors, representing 50% of their annual retainer.

Note 9 — Share-Based Awards

As of March 31, 2010, 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 is available for grant under this plan. 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, granted to our named executive officers, and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options granted to our directors vest immediately.

During the three months ended March 31, 2010, we recorded a compensation expense accrual of \$16,274 which was allocated as an addition of \$12,508 to lease operating expenses and \$26,149 was capitalized to unevaluated gas properties, offset by a reduction of general and administrative expense of \$(22,383). The future compensation cost of all the outstanding awards is \$583,464 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 0.96 years. During the three months ended March 31, 2009, we recorded a compensation expense accrual of \$376,137 which was allocated among lease operating expenses for \$26,570, general and administrative expenses for \$285,864, and \$63,704 was capitalized to unevaluated gas properties.

During the three months ended March 31, 2010, no stock options were granted. During the three months ended March 31, 2009, 720,519 stock options were granted. 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.

Incentive Stock Options

The table below summarizes incentive stock option activity for the three months ended March 31, 2010:

	<u>Number of Options</u>	<u>Weighted Average Exercise Price</u>	<u>Average Remaining Contractual Life</u>	<u>Aggregate Intrinsic Value</u>
Outstanding at December 31, 2009.....	997,786	\$ 3.95		
Forfeited.....	<u>(76,878)</u>	\$ 1.86		
Outstanding at March 31, 2010.....	<u>920,908</u>	\$ 4.12	4.77	\$ 85,873
Options exercisable at March 31, 2010.....	<u>494,941</u>	\$ 5.87	4.02	<u>\$ 28,624</u>

During the three months ended March 31, 2010, no incentive stock options were granted or exercised. During the three months ended March 31, 2009, 606,507 incentive stock options were granted with a weighted average grant-date fair value of \$200,147. During the three months ended March 31, 2009, no incentive stock options were exercised.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three months ended March 31, 2010:

	<u>Number of Options</u>	<u>Weighted Average Exercise Price</u>	<u>Average Remaining Contractual Life</u>	<u>Aggregate Intrinsic Value</u>
Outstanding at December 31, 2009.....	1,400,760	\$ 3.61		
Forfeited.....	<u>(10,212)</u>	\$ 0.72		
Outstanding at March 31, 2010.....	<u>1,390,548</u>	\$ 3.63	3.30	\$ 17,646
Options exercisable at March 31, 2010.....	<u>1,114,196</u>	\$ 3.05	2.94	<u>\$ —</u>

During the three months ended March 31, 2010, no non-qualified stock options were granted or exercised. During the three months ended March 31, 2009, 114,012 non-qualified stock options were granted with a weighted average grant-date fair value of \$38,192. During the three months ended March 31, 2009, no non-qualified stock options were exercised.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the three months ended March 31, 2010:

	<u>Number of Shares</u>	<u>Weighted Average Value at Grant Date</u>
Non-vested restricted stock at December 31, 2009	311,684	\$ 6.57
Vested.....	(69,362)	\$ 6.59
Forfeited	<u>(66,194)</u>	\$ 6.50
Non-vested restricted stock at March 31, 2010	<u>176,128</u>	\$ 6.59

During the three months ended March 31, 2010, no shares of restricted stock were granted and 69,362 shares of restricted stock vested with a grant date fair value of \$456,795. During the three months ended March 31, 2009, 48,397 shares of restricted stock vested with a grant date fair value of \$310,225.

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 Gas Company LLC (“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 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, denying CNX’s demurrers with respect to four of our five state-law antitrust claims for monopolization and attempted monopolization and upholding only the demurrers to one antitrust theory and 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. Unless we reach a commercially reasonable settlement, we intend to pursue discovery and trial in this matter.

Environmental and Regulatory

As of March 31, 2010, 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 March 31, 2010. For tax reporting purposes, we have federal and state NOL’s of approximately \$100.5 million and \$109.1 million, respectively, at March 31, 2010 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.

Income tax expense for the three months ended March 31, 2010 was different than the amount computed using the statutory rate as follows:

	<u>U.S.</u>		<u>Canada</u>		<u>Total</u>	
Amount computed using statutory rates.....	3,720,082	34.0%	(145,623)	26.0%	3,574,459	34.4%
State income taxes—net of federal benefit	491,711	4.5%	—	0.0%	491,711	4.7%
Valuation Allowance	—	0.0%	145,623	-26.0%	145,623	1.4%
Nondeductible items and other	142,383	1.3%	—	0.0%	142,383	1.4%
Income tax (benefit) provision.....	<u>4,354,176</u>	39.8%	<u>—</u>	0.0%	<u>4,354,176</u>	41.9%

Income tax expense for the three months ended March 31, 2009 was different than the amount computed using the statutory rate as follows:

	<u>U.S.</u>		<u>Canada</u>		<u>Total</u>	
Amount computed using statutory rates.....	(47,127,586)	34.0%	(523,163)	26.0%	(47,650,749)	33.9%
State income taxes—net of federal benefit	(5,978,816)	4.3%	—	0.0%	(5,978,816)	4.2%
Valuation Allowance	—	0.0%	523,163	-26.0%	523,163	-0.4%
Nondeductible items and other	209,493	-0.1%	—	0.0%	209,493	-0.1%
Income tax (benefit) provision.....	<u>(52,896,909)</u>	38.2%	<u>—</u>	0.0%	<u>(52,896,909)</u>	37.6%

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 expressions 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, 2009, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 31, 2010.

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 March 31, 2010, we control a total of approximately 164,000 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 attractive investment opportunities.

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 above current levels, maintain borrowing capacity at or near current levels under our revolving credit facility, and the availability of future debt and equity financing on satisfactory terms. Our ability to fund new opportunities and compete for and retain the qualified personnel necessary to conduct our business is also dependent upon our financial resources. Prolonged weakness in the global economy and in natural gas prices, which may affect both our cash flows and the value of our gas reserves, limitations on our ability to replace production through drilling activities, a material adverse change in our gas reserves due to factors other than gas pricing changes, our ability to transport our gas to markets, drilling costs, lower than expected production rates, material adverse outcomes from lawsuits and other factors, many of which are beyond our control, may adversely affect our ability to fund our anticipated capital expenditures, pursue property acquisitions, and compete for qualified personnel, among other things.

We expect to fund our remaining capital expenditure budget for 2010 of \$7.3 million from our operating cash flows. If our cash flows are not sufficient to fund all of our planned capital projects, we expect to reduce our capital budget accordingly. The amount and timing of our expenditures are subject to change based upon market conditions, results of operations 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 borrowing base redeterminations under our revolving credit facility.

Effective March 30, 2010, the parties to the revolving credit facility agreement unanimously approved the Third Amendment to the revolving credit facility ("Third Amendment") as summarized below:

- The maturity date of the revolving credit facility was extended four months to May 6, 2011 pursuant to a request by the Company.
- Pursuant to a request by the Company, the borrowing base was reduced to \$123.0 million and the bank group agreed that (1) the next borrowing base determination would be as of June 15, 2010, and (2) the bank group agreed not to call for a determination of the borrowing base prior to that date.
- The minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability under the revolving credit agreement, is adjusted to .80 to 1 solely for the quarter ended March 31, 2010.

- The outstanding balances on the revolving credit facility will 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 2.625%, or (b) the adjusted LIBOR rate, plus a margin of 3.50%.

As part of the completion of the Third Amendment, the Company was required to pay a non-refundable fee to its bank group in the amount of \$307,500.

On March 29, 2010, we executed commitment letters with NGP Capital Resources Company ("NGPC") and North Shore Energy, LLC ("North Shore"), an affiliate of our largest stockholder, whereby NGPC and North Shore have agreed to the preliminary terms of a commitment to purchase up to \$20 million each (\$40 million in the aggregate) of the Company's convertible preferred stock in the event that a proposed rights offering of the convertible preferred stock is not fully subscribed by our common stockholders. Our Board of Directors approved the execution of the commitment letters after its receipt of a recommendation to do so by a Special Committee comprised of two independent directors with no affiliation with our largest stockholder. The Special Committee retained the services of independent legal counsel and a financial advisor in evaluating and formulating its recommendation to the Board.

NGPC and North Shore each received an initial non-refundable payment of \$250,000 from the Company in exchange for the commitment letters. The initial payment will be credited against a \$600,000 fee due to each of NGPC and North Shore upon the closing of a rights offering and backstop commitment. Under the terms of the proposed \$40 million rights offering, we would distribute, at no charge to the holders of our common stock, rights to purchase up to an aggregate of 4,000,000 new shares of convertible preferred stock at a subscription price of \$10.00 per share. The number of rights to be distributed per share of common stock would be determined after our board of directors approves and sets a record date for the rights offering. Any rights offering will be made only by means of a prospectus supplement and accompanying prospectus to our effective registration statement on Form S-3 (Registration No. 333-163193). We are currently negotiating the terms of a definitive backstop arrangement with NGPC and North Shore. In the event that we are able to complete the proposed rights offering, we intend to use the net proceeds to repay a portion of our outstanding indebtedness. We cannot assure that we will be successful in completing the proposed rights offering on the terms outlined above, and any discussion of the proposed rights offering in this filing on Form 10-Q does not constitute an offer or the solicitation of an offer of the Company's securities.

We currently have limited borrowing availability under our revolving credit facility, which matures on May 6, 2011, and we have no assurances that our lenders will extend the maturity date. Accordingly, because the successful completion of the proposed rights offering cannot be assured, we will continue to explore alternatives for additional financing for the Company. These alternatives may include private or public offerings of debt or equity securities or the sale of assets. The terms, timing and structure of any such financing or sale will depend on several factors, including market conditions, execution risk, timing, possible dilution of existing shareholders and relative cost of the various financing alternatives. There can be no assurance that we will be able to obtain debt or equity financing, including the proposed rights offering, or complete an asset sale on terms favorable to us, or at all.

Changes in natural gas prices may significantly affect our revenues, financial condition, cash flows, natural gas reserves 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 may materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Declining or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Although we will attempt to cure any non-compliance with covenants in our revolving credit facility in the event they occur, no assurance can be given that we will be able to cure such non-compliance. 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.

Operational Developments

Pond Creek— No new wells were added to sales in the three months ended March 31, 2010. We have a total of 243 net producing wells in the Pond Creek field. Net gas sales were 14.4 MMcf per day for the three months ended March 31, 2010, as compared to 14.3 MMcf per day for the three months ended March 31, 2009. We plan to drill at least eight new wells in the Virginia portion of the Pond Creek field prior to August 16, 2010, three of which were drilled in January, 2010. If the proposed rights offering or other alternate financing transactions are completed, we will consider increasing spending in the area later this year.

Lasher— No new wells were added to sales in the three months ended March 31, 2010. Net gas sales averaged 0.4 MMcf per day from 18 producing wells for the three months ended March 31, 2010, as compared to 0.2 MMcf per day for the three months ended March 31, 2009.

Gurnee— No new wells were added to sales in the three months ended March 31, 2010. Net gas sales were 5.3 MMcf per day from a total of 219 producing wells in the Gurnee field for the three months ended March 31, 2010, as compared to 6.2 MMcf per day for the three months ended March 31, 2009. We have no drilling scheduled in Gurnee in 2010. In 2009, we fraced a previously uncompleted coal group in three nearby wells in the Gurnee field to test three new frac techniques. We have subsequently fraced one of the test wells a second time using the most effective technique with significantly improved results. We recently applied this technique to all of the coal groups previously fraced in an existing wellbore. The results of this frac is currently being evaluated. We are planning to spend up to \$1.2 million testing this frac technique in 2010.

Garden City— Our focus in the Garden City Chattanooga Shale prospect is directed at determining a viable solution to handle and dispose of produced water. We are currently reviewing several alternatives including a reverse osmosis system. We are evaluating the results of our reverse osmosis unit in Pond Creek to determine if this is an economical solution for Garden City as well. However, due to low gas prices and the high cost of trucking produced water the Garden City test wells remain temporarily shut in.

Peace River— No new wells were added to sales in the three months ended March 31, 2010. Net gas sales averaged 0.1 MMcf per day from 4 net producing wells for the three months ended March 31, 2010, as compared to 0.1 MMcf per day for the three months ended March 31, 2009. On April 15, 2010, we shut in our wells in the Peace River field, located in British Columbia as a result of decreased natural gas prices and longer than expected dewatering time.

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 months ended March 31, 2010.

Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three months ended March 31, 2010 and 2009. 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 March 31,	
	2010	2009
Gas sales.....	\$ 9,884	\$ 9,453
Lease operating expenses.....	\$ 3,107	\$ 4,569
Compression and transportation expenses.....	1,005	1,450
Production taxes.....	208	367
Total production expenses.....	\$ 4,320	\$ 6,386
Net sales volumes (MMcf).....	1,820	1,887
Pond Creek field.....	1,295	1,291
Gurnee field.....	474	557
Per Mcf data (\$/Mcf):		
Average natural gas sales price.....	\$ 5.43	\$ 5.01
Average natural gas sales price realized(1).....	\$ 6.23	\$ 6.45
Lease operating expenses.....	\$ 1.71	\$ 2.42
Pond Creek field.....	\$ 1.33	\$ 1.73
Gurnee field.....	\$ 2.14	\$ 3.15
Compression and transportation expenses.....	\$ 0.55	\$ 0.77
Pond Creek field.....	\$ 0.58	\$ 0.77
Gurnee field.....	\$ 0.37	\$ 0.59
Production taxes.....	\$ 0.11	\$ 0.19
Pond Creek field.....	\$ 0.18	\$ 0.15
Gurnee field (2).....	\$ (0.07)	\$ 0.31
Total production expenses.....	\$ 2.37	\$ 3.38
Pond Creek field.....	\$ 2.09	\$ 2.65
Gurnee field.....	\$ 2.44	\$ 4.05
Depletion.....	\$ 0.83	\$ 1.52

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

(2) The company received a production tax refund related to prior production in the Gurnee field in March 2010.

Results of Operations

Three Months Ended March 31, 2010 compared with Three Months Ended March 31, 2009

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 March 31,		
	2010	2009	Change
	(In thousands)		
Gas sales.....	\$ 9,884	\$ 9,453	5%
Lease operating expenses.....	\$ 3,107	\$ 4,569	-32%
Compression expense.....	\$ 685	\$ 833	-18%
Transportation expense.....	\$ 320	\$ 617	-48%
Production taxes.....	\$ 208	\$ 367	-43%
Impairment of gas properties.....	\$ —	\$ 139,712	NM
Depreciation, depletion and amortization.....	\$ 1,645	\$ 3,037	-46%
General and administrative.....	\$ 1,478	\$ 2,973	-50%
Realized gains on derivative contracts.....	\$ (1,460)	\$ (2,723)	-46%
Unrealized gains from the change in market value of open derivative contracts.....	\$ (7,642)	\$ (186)	NM
Interest expense, net of amounts capitalized.....	\$ (1,244)	\$ (983)	27%
Income tax expense (benefit).....	\$ 4,354	\$ (52,897)	NM

NM-Not Meaningful

Gas sales. Gas sales increased by \$0.43 million, or 5%, to \$9.88 million compared to the prior year quarter. The increase in gas sales was a result of increased gas prices partially offset by decreased production. Production decreased 4% and average gas prices increased 8%, excluding hedging transactions. The \$0.43 million increase in gas sales consisted of a \$0.77 million increase in prices and a \$0.33 million decrease in production.

Lease operating expenses. Lease operating expenses decreased by \$1.46 million, or 32%, to \$3.11 million compared to the prior year quarter. The decrease in lease operating expenses consisted of a \$1.30 million decrease in costs and a \$0.16 million decrease in production. The \$1.30 decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

Compression expense. Compression expense decreased by \$0.15 million, or 18%, to \$0.68 million compared to the prior year quarter. The \$0.15 million decrease was comprised of a \$0.12 million decrease in costs and a \$0.03 decrease in production. The \$0.12 decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

Transportation expense. Transportation expense decreased by \$0.30 million, or 48%, to \$0.32 million compared to the prior year quarter. The \$0.30 million decrease was primarily due to decreased costs resulting from the permanent release of excess firm transportation capacity effective May 1, 2009.

Production taxes. Production taxes decreased by \$0.16 million, or 43%, to \$0.21 million compared to the prior year quarter. The \$0.16 million decrease in production taxes was primarily due to a refund received in March 2010 for production taxes related to our Gurnee field.

Impairment of gas properties. At March 31, 2009, the carrying value of the Company's gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the current year period.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by \$1.39 million, or 46%, to \$1.65 million compared to the prior year quarter. The depreciation, depletion and amortization decrease consisted of a \$0.11 million decrease in production and a \$1.28 million decrease in the depletion rate.

General and administrative. General and administrative expenses decreased by \$1.49 million, or 50%, to \$1.48 million compared to the prior year quarter. The decrease in general and administrative expenses was primarily due to a company-wide cost reduction strategy implemented in April 2009.

Realized gains on derivative contracts. Realized gains on derivative contracts decreased by \$1.26 million. Or 46%, to \$1.46 million compared to 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 gains from the change in market value of open derivative contracts. Unrealized gains from the change in market value of open derivative contracts increased by \$7.45 million to \$7.64 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. The gain was a result of the increased estimated fair value of our natural gas derivative contracts resulting from decreased natural gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by \$0.26 million, or 27%, to \$1.24 million compared to the prior year quarter. The increase was primarily due to a \$0.24 million loss on our interest rate swaps in the current year quarter.

Income tax expense (benefit). Income tax expense was \$4.35 million in the current year period. The effective tax rate for the period was 41.9%. Income tax expense for the three months ended March 31, 2010 was different than the amount computed using the statutory rate as follows:

	<u>U.S.</u>		<u>Canada</u>		<u>Total</u>	
Amount computed using statutory rates.....	3,720,082	34.0%	(145,623)	26.0%	3,574,459	34.4%
State income taxes—net of federal benefit	491,711	4.5%	—	0.0%	491,711	4.7%
Valuation Allowance	—	0.0%	145,623	-26.0%	145,623	1.4%
Nondeductible items and other	142,383	1.3%	—	0.0%	142,383	1.4%
Income tax (benefit) provision.....	<u>4,354,176</u>	39.8%	<u>—</u>	0.0%	<u>4,354,176</u>	41.9%

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the three months ended March 31, 2010 and 2009 were \$4.7 million and \$2.2 million, respectively. Cash flows from operations of \$4.7 million for the three months ended March 31, 2010 were sufficient to fund net cash used in investing activities of \$1.4 million, which primarily includes capital expenditures for the development of our gas properties, and cash used in financing activities of \$3.3 million, primarily related to credit facility net repayment.

As of March 31, 2010 and 2009, we had working capital of approximately \$3.7 million and \$2.7 million, respectively.

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 the proposed rights offering would provide the ability to develop our existing properties.

If natural gas prices remain at a depressed level for an extended period, our ability to finance our planned capital expenditures could be affected negatively. Consistent with our intention to keep our capital expenditures in line with our estimated operating cash flows, further reduction in spending may be necessary. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of estimated proved reserves and our lender's expectation of future natural gas prices. There is no assurance, absent the completion of new financing such as the proposed rights offering, that our bank group will not decrease the availability under our current revolving credit facility or decline to extend its current maturity. If either our estimated proved reserves or natural gas prices decrease, funding available to us under our revolving credit facility could be further negatively affected. If our cash flows are less than anticipated, amounts available for borrowing under our revolving credit facility are reduced, we are unable to sell equity at acceptable prices, or we are unable to find alternative sources of financing, we may be forced to defer planned capital expenditures.

The ongoing 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, and we do not expect that it will be materially impacted in the future. 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 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 three years, 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 70% 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.

Commodity Price Risk and Related Hedging Activities

At March 31, 2010, we had the following natural gas collar positions:

<u>Period</u>	<u>Volume (MMBtu)</u>	<u>Sold Ceiling</u>	<u>Bought Floor</u>	<u>Sold Floor</u>	<u>Fair Value</u>
April through October 2010.....	856,000	\$ 6.80	\$ 5.50	\$ 3.50	\$ 1,172,051
April through October 2010.....	856,000	\$ 6.35	\$ 5.50	—	1,258,999
November 2010 through March 2011	604,000	\$ 7.45	\$ 6.50	—	862,572
	<u>2,316,000</u>				<u>\$ 3,293,622</u>

At March 31, 2010, we had the following natural gas swap positions:

<u>Period</u>	<u>Volume (MMBtu)</u>	<u>Price</u>	<u>Fair Value</u>
April through October 2010.....	856,000	\$ 5.70	\$ 1,389,451
April through October 2010.....	642,000	\$ 6.30	1,426,463
November 2010 through March 2011.....	604,000	\$ 6.67	883,023
November 2010 through March 2011.....	906,000	\$ 7.27	1,860,622
April 2011 through October 2011.....	856,000	\$ 6.37	984,468
April 2011 through October 2011.....	856,000	\$ 5.37	137,364
November 2011 through March 2012.....	608,000	\$ 7.12	688,527
November 2011 through March 2012.....	608,000	\$ 6.12	93,758
April 2012 through October 2012.....	856,000	\$ 5.73	128,447
November 2012 through March 2013.....	604,000	\$ 6.42	80,999
	<u>7,396,000</u>		<u>\$ 7,673,122</u>

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 ASC 815-20-25. 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 March 31, 2010, we had the following interest rate swaps:

<u>Description</u>	<u>Effective date</u>	<u>Designated maturity date</u>	<u>Fixed rate (1)</u>	<u>Notional amount</u>	<u>Fair Value</u>
Floating-to-fixed swap.....	12/14/2007	12/14/2010	3.86%	\$ 15,000,000	\$ (382,728)
Floating-to-fixed swap.....	5/13/2008	5/13/2010	3.07%	\$ 5,000,000	(33,033)
Floating-to-fixed swap.....	1/6/2009	1/6/2011	1.38%	\$ 5,000,000	(37,954)
				<u>\$ 25,000,000</u>	<u>\$ (453,715)</u>

(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:

	<u>Three Months Ended March 31,</u>	
	<u>2010</u>	<u>2009</u>
Capital expenditures:		
Leasehold acquisition.....	\$ 129,159	\$ 639,973
Exploration.....	—	9,607
Development.....	1,364,121	2,045,935
Other items (primarily capitalized overhead and interest).....	160,836	559,331
Total capital expenditures.....	<u>\$ 1,654,116</u>	<u>\$ 3,254,846</u>

We expect our capital expenditure budget for 2010 of \$7.3 million to be funded from our estimated operating cash flows. If the amount and timing of cash flows are reduced, we will reduce our capital budget. 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 borrowing base redeterminations under our revolving credit facility.

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 volume of initial and subsequent natural gas production volumes.

Currently, there is a significant 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, tougher credit standards, 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 our revolving credit facility, some could be considered take-over candidates. Although we have no indication that any such transactions would impact our current revolving credit facility, the possibility does exist. 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 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 may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. A decline in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our 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.

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our revolving credit facility and proceeds from potential transactions such as the proposed rights offering will provide the ability to develop certain existing properties.

Beginning in early 2009, we began implementing countermeasures in response to the above referenced trends in order to enhance our ability to execute our business strategy. These countermeasures included reducing costs, increasing hedging to reduce exposure to volatile natural gas prices and limiting capital spending. We are evaluating additional measures in light of the current credit and commodity markets including the proposed rights offering, selling assets, entering into joint venture agreements with industry partners to reduce our capital outlays, and alternate forms of financing.

Revolving Credit Facility

Effective March 30, 2010, the parties to the revolving credit facility agreement unanimously approved the Third Amendment to the revolving credit facility ("Third Amendment") as summarized below:

- The maturity date of the revolving credit facility was extended four months to May 6, 2011 pursuant to a request by the Company.
- Pursuant to a request by the Company, the borrowing base was reduced to \$123 million and the bank group agreed that (1) the next borrowing base determination would be as of June 15, 2010, and (2) the bank group agreed not to call for a determination of the borrowing base prior to that date.
- The minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability under the revolving credit agreement, is adjusted to .80 to 1 solely for the quarter ended March 31, 2010.
- 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 2.625%, or (b) the adjusted LIBOR rate, plus a margin of 3.50%.

As part of the completion of the Third Amendment, the Company was required to pay a non-refundable fee to its bank group in the amount of \$307,500.

Commitments for Additional Financing

On March 29, 2010, we executed commitment letters with NGP Capital Resources Company ("NGPC") and North Shore Energy, LLC ("North Shore"), an affiliate of our largest stockholder, whereby NGPC and North Shore have agreed to the preliminary terms of a commitment to purchase up to \$20 million each (\$40 million in the aggregate) of the Company's convertible preferred stock in the event that a proposed rights offering of the convertible preferred stock is not fully subscribed by our common stockholders. Our Board of Directors approved the execution of the commitment letters after its receipt of a recommendation to do so by a Special Committee comprised of two independent directors with no affiliation with our largest stockholder. The Special Committee retained the services of independent legal counsel and a financial advisor in evaluating and formulating its recommendation to the Board.

NGPC and North Shore each received an initial non-refundable payment of \$250,000 from the Company in exchange for the commitment letters. The initial payment will be credited against a \$600,000 fee due to each of NGPC and North Shore upon the closing of a rights offering and backstop commitment.

The proposed rights offering will be made only by means of a prospectus supplement and accompanying prospectus that will contain the specific terms of the proposed transaction and will be provided to our stockholders in connection with any such offering. The disclosure in this filing on Form 10-Q does not constitute an offer or the solicitation of an offer of the Company's securities. Any such offer will only be made by registration under federal and state securities laws, or pursuant to an applicable exemption from registration thereunder.

Proposed Rights Offering

Under the terms of the proposed \$40 million rights offering, we would distribute, at no charge to the holders of our common stock, rights to purchase up to an aggregate of 4,000,000 new shares of convertible preferred stock at a subscription price of \$10.00 per share. The number of rights to be distributed per share of common stock would be determined when our Board of Directors sets a record date for the rights offering and would be set forth in a prospectus supplement to our effective registration statement on Form S-3. The prospectus supplement would be distributed to stockholders of record as of the record date. Each whole right would entitle a holder to purchase one share of convertible preferred stock at the subscription price. In the event that our stockholders do not subscribe for all 4,000,000 shares of preferred stock offered, NGPC and North Shore would purchase the remaining unsubscribed shares of preferred stock pursuant to the terms of a backstop arrangement. We are currently negotiating the terms of a definitive backstop arrangement with NGPC and North Shore. Consummation of the rights offering is subject to the execution of a definitive backstop agreement between the Company, NGPC and North Shore, completion of title and environmental due diligence satisfactory to NGPC and North Shore, the approval of our stockholders and other terms and conditions described in the commitment letters. We cannot assure that we will be successful in completing the proposed preferred stock rights offering on the terms outlined herein.

Terms of Proposed Backstop Commitment

Under the proposed terms set forth in the commitment letters, NGPC and North Shore agree to purchase all shares of convertible preferred stock that remain unsubscribed as a result of any unexercised rights by our common stockholders during the proposed rights offering. NGPC and North Shore each would purchase up to \$20 million of convertible preferred stock assuming no stockholder subscriptions and would participate equally in any unsubscribed shares of convertible preferred stock.

Under the terms set forth in the commitment letters, NGPC and North Shore are entitled to receive a backstop fee of \$600,000 each, or \$1.2 million in the aggregate, upon the closing of the rights offering and backstop commitment. An initial \$500,000 aggregate payment already made by the Company will be credited against the backstop fee. In addition, in the event that less than \$15 million of convertible preferred stock is available for NGPC or North Shore to purchase following the rights offering, the Company will be required to pay NGPC and/or North Shore an additional fee of 3% of the shortfall (i.e., the difference between \$15 million and the amount of convertible preferred stock actually purchased). We have agreed to pay or reimburse NGPC and North Shore for all reasonable costs and out-of-pocket expenses relating to their commitments.

As additional consideration for their commitment to backstop the proposed rights offering, NGPC and North Shore would each be entitled to appoint one member to our board of directors so long as it held a threshold amount of convertible preferred stock, and our board would be comprised of no more than nine directors. Certain Company actions would require the approval of a supermajority (70%) of our board, including our annual operating budget, capital expenditure budget and general and administrative budget.

The commitment letters also outline certain covenants that are expected to be included in the backstop agreement, including:

- A debt incurrence test during the first year following closing of the proposed rights offering;
- A maximum debt-to-EBITDA ratio, which would be less restrictive than the ratio required under our senior credit facility;
- A limit on general and administrative expenses; and
- A \$5 million reduction in Company debt each year that a threshold amount of convertible preferred stock remains outstanding.

In addition, so long as a threshold amount of convertible preferred stock remains outstanding, the Company may not incur additional material debt, issue any equity senior or on par with the convertible preferred stock, engage in any material acquisitions or other significant corporate transactions, incur any exploration expenses, or engage in certain other activities without the consent of NGPC and North Shore.

We currently have limited borrowing availability under our revolving credit facility, which matures on May 6, 2011, and we have no assurances that our lenders will extend the maturity date. Accordingly, because the successful completion of the proposed rights offering cannot be assured, we will continue to explore alternatives for additional financing for the Company. These alternatives may include private or public offerings of debt or equity securities or the sale of assets. The terms, timing and structure of any such financing or sale will depend on several factors, including market conditions, execution risk, timing, possible dilution of existing shareholders and relative cost of the various financing alternatives. There can be no assurance that we will be able to obtain debt or equity financing, including the proposed rights offering, or complete an asset sale on terms favorable to us, or at all.

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 the 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 ongoing 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.

Contractual Commitments

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

Recent Pronouncements

In January 2010, the FASB issued Update No. 2010-06—Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This Update provides amendments to Subtopic 820-10 that require new disclosures for transfers in and out of Levels 1 and 2. This Update also clarifies existing disclosures for level of disaggregation, as well as valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009. See additional disclosure provided in Note 6 — Derivative Instruments and Hedging Activities within Notes to Consolidated Financial Statements (Unaudited).

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 the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the three months ended March 31, 2010, a 10% decrease in the prices received for natural gas production would have had an approximate \$1.0 million impact on our revenues, which would be partially offset by gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. At March 31, 2010, we had \$117.2 million outstanding under our revolving credit facility. For the three months ended March 31, 2010 and 2009, interest on the borrowings averaged 3.14% per annum and 3.31% per annum, respectively. Borrowing availability at March 31, 2010 was \$5.8 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 March 31, 2010, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately \$0.92 million. \$25 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 exploratory 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 Canadian project is exploratory, changes in the exchange rate do not 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 March 31, 2010 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 Control 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.

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 Gas Company LLC (“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 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, denying CNX’s demurrers with respect to four of our five state-law antitrust claims for monopolization and attempted monopolization and upholding only the demurrers to one antitrust theory and 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. Unless we reach a commercially reasonable settlement, we intend to pursue discovery and trial in this matter.

Environmental and Regulatory

As of March 31, 2010, 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 no changes from the risk factors disclosed in the “Risk Factors” section of our Annual Report on Form 10-K for the year ended December 31, 2009.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Reserved

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.

INDEX TO EXHIBITS

Exhibit Number	Exhibits
10.1	Commitment Letter dated effective March 29, 2010 by and between NGP Capital Resources Company and GeoMet, Inc (incorporated herein by reference to Exhibit 10.21 to the Company's 10-K filed on March 31, 2010)
10.2	Commitment Letter dated effective March 29, 2010 by and between North Shore Energy, LLC and GeoMet, Inc (incorporated herein by reference to Exhibit 10.22 to the Company's 10-K filed on March 31, 2010)
10.3	Third Amendment to Third Amended and Restated Credit Agreement dated March 30, 2010 by and among Bank of America, N.A., as administrative agent, and certain financial institutions, as lenders (incorporated herein by reference to Exhibit 10.23 to the Company's 10-K filed on March 31, 2010)
31.1*	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).
31.2*	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).
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

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of GeoMet, Inc. (the "Company") for the quarter ended March 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. Darby Seré, Chief Executive Officer, and I, William C. Rankin, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to our knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. DARBY SERÉ

/s/ WILLIAM C. RANKIN

J. Darby Seré
Chief Executive Officer
April 28, 2010

William C. Rankin
Chief Financial Officer
April 28, 2010

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.