GeoMet, Inc.
Form 10-Q
May 06, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

OR

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

For the transition period from ______ to ______

Commission File Number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of incorporation or organization)	**(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. x Yes ¨ No

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

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

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

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

As of May 2, 2011, there were 39,974,554 shares issued and outstanding of GeoMet, Inc. s common stock, par value $0.001 per share.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Part I. Financial Information

Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	March 31, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 625,422	$ 536,533
Accounts receivable, both amounts net of allowance of $60,848	2,331,864	2,600,319
Inventory	831,967	1,002,207
Derivative asset natural gas hedges	5,193,701	7,087,775
Other current assets	835,606	951,622
Total current assets	9,818,560	12,178,456
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	479,851,967	475,917,727
Other property and equipment	3,407,720	3,405,502
Total property and equipment	483,259,687	479,323,229
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(375,678,778)	(373,235,875)
Property and equipment net	107,580,909	106,087,354
Other noncurrent assets:		
Derivative asset natural gas hedges	1,230,673	2,186,767
Deferred income taxes	47,831,896	48,202,861
Other	1,286,233	1,430,584
Total other noncurrent assets	50,348,802	51,820,212
TOTAL ASSETS	$ 167,748,271	$ 170,086,022
LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 5,766,352	$ 5,950,861
Accrued liabilities	1,816,332	2,306,020
Deferred income taxes	1,841,220	2,206,531
Derivative liability interest rate swaps		4,592
Asset retirement liability	33,832	32,893
Current portion of long-term debt	85,706	132,743
Total current liabilities	9,543,442	10,633,640

Long-term debt	78,841,253	80,863,419
Asset retirement liability	5,618,071	5,465,798
Other long-term accrued liabilities	32,581	40,728
TOTAL LIABILITIES	94,035,347	97,003,585
Commitments and contingencies (Note 11)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,526,658; redemption amount $42,781,240; $.001 par value; 7,401,832 shares authorized, 4,278,124 and 4,148,538 shares were issued and outstanding at March 31, 2011 and December 31, 2010, respectively.	23,796,990	22,074,320
Stockholders Equity:		
Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 39,858,013 and 39,758,484 at March 31, 2011 and December 31, 2010, respectively	39,858	39,744
Treasury stock 10,432 shares at March 31, 2011 and December 31, 2010	(94,424)	(94,424)
Paid-in capital	205,994,292	207,548,596
Accumulated other comprehensive loss	(1,312,845)	(1,324,154)
Retained deficit	(154,467,657)	(154,918,736)
Less notes receivable	(243,290)	(242,909)
Total stockholders equity	49,915,934	51,008,117
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY	$ 167,748,271	$ 170,086,022

See accompanying Notes to Consolidated Financial Statements (Unaudited)

3

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

	Three Months Ended March 31, 2011	2010
Revenues:		
Gas sales	$ 7,851,048	$ 9,883,686
Operating fees and other	72,772	74,292
Total revenues	7,923,820	9,957,978
Expenses:		
Lease operating expense	2,972,755	3,107,371
Compression and transportation expense	916,231	1,004,447
Production taxes	322,388	208,229
Depreciation, depletion and amortization	1,632,968	1,645,365
General and administrative	1,439,190	1,477,725
Realized gains on derivative contracts	(3,497,062)	(1,460,128)
Unrealized losses (gains) from the change in market value of open derivative contracts	2,850,168	(7,642,042)
Total operating expenses (gains)	6,636,638	(1,659,033)
Operating income	1,287,182	11,617,011
Other income (expense):		
Interest income	4,474	25,804
Interest expense	(840,069)	(1,244,160)
Other income (expense)	4,682	(17,327)
Total other income (expense):	(830,913)	(1,235,683)
Income before income taxes	456,269	10,381,328
Income tax expense	(5,190)	(4,354,176)
Net income	$ 451,079	$ 6,027,152
Accretion of Series A Convertible Redeemable Preferred Stock	(423,143)	
Dividends paid on Series A Convertible Redeemable Preferred Stock	(1,296,418)	
Net (loss) income available to common stockholders	$ (1,268,482)	$ 6,027,152
(Loss) income per share:		
Net (loss) income per common share		
Basic	$ (0.03)	$ 0.15
Diluted	$ (0.03)	$ 0.15
Weighted average number of common shares:		
Basic	39,470,284	39,158,985
Diluted	39,470,284	39,236,844

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

	Common Stock Par Value $0.001 (shares outstanding)	Common Stock Par Value $0.001	Treasury Stock	Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Notes Receivable	Total Stockholders Equity
Balance at January 1, 2010	39,293,983	$ 39,294	$ (94,424)	$ 189,681,816	$ (1,768,521)	$ (160,710,889)	$ (239,537)	$ 26,907,739
Stock-based compensation		(77)		16,028				15,951
Purchase and cancellation of treasury stock	(300)							
Accrued interest on notes receivable				2,762			(2,762)	
Comprehensive income:								
Net income						6,027,152		6,027,152
Gain on interest rate swap, net of income taxes of $103,198					166,953			166,953
Foreign currency translation adjustment, net of income taxes of $0					8,833			8,833
Total comprehensive income								6,202,938
Balance at March 31, 2010	39,293,683	$ 39,217	$ (94,424)	$ 189,700,606	$ (1,592,735)	$ (154,683,737)	$ (242,299)	$ 33,126,628
Balance at January 1, 2011	39,744,071	$ 39,744	$ (94,424)	$ 207,548,596	$ (1,324,154)	$ (154,918,736)	$ (242,909)	$ 51,008,117
Stock-based compensation	14,413	15		163,584				163,599
Purchase and cancellation of treasury stock	(819)	(1)		1				
Exercise of stock options	1,932	2		1,389				1,391
Option exchange	98,416	98		(98)				
Dividends paid in-kind				(1,295,860)				(1,295,860)
Dividends paid in cash				(558)				(558)
Accretion of discount recorded for Series A Convertible Redeemable Preferred Stock				(423,143)				(423,143)
Accrued interest on notes receivable				381			(381)	

Comprehensive income:								
Net income						451,079		451,079
Gain on interest rate swap, net of income taxes of $6,714					10,862			10,862
Foreign currency translation adjustment, net of income taxes of $0					447			447
Total comprehensive income								462,388
Balance at March 31, 2011	39,858,013	$ 39,858	$ (94,424)	$ 205,994,292	$ (1,312,845)	$ (154,467,657)	$ (243,290)	$ 49,915,934

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended March 31, 2011	2010
Cash flows provided by operating activities:		
Net income	$ 451,079	$ 6,027,152
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	1,632,968	1,645,365
Amortization of debt issuance costs	142,218	73,227
Deferred income tax (benefit) expense	(1,060)	4,347,926
Unrealized losses (gains) from the change in market value of open derivative contracts	2,863,152	(7,642,042)
Stock-based compensation	133,899	(10,162)
Loss on sale of other assets		19,498
Accretion expense	135,170	120,486
Changes in operating assets and liabilities:		
Accounts receivable	268,540	(114,554)
Other current assets	111,157	639,279
Accounts payable	(1,327,362)	(742,624)
Other accrued liabilities	(508,023)	372,404
Net cash provided by operating activities	3,901,738	4,735,955
Cash flows used in investing activities:		
Capital expenditures	(1,760,475)	(1,521,283)
Proceeds from sale of other property and equipment		79,370
Other assets	9,306	25,338
Net cash used in investing activities	(1,751,169)	(1,416,575)
Cash flows used in financing activities:		
Proceeds from revolving credit facility borrowings	7,200,000	5,800,000
Payments on revolving credit facility	(9,200,000)	(8,100,000)
Proceeds from exercise of stock options	1,389	
Deferred financing costs	2,885	(887,378)
Payments on other debt	(69,203)	(63,729)
Dividends paid	(558)	
Net cash used in financing activities	(2,065,487)	(3,251,107)
Effect of exchange rate changes on cash	3,807	19,771
Increase in cash and cash equivalents	88,889	88,044
Cash and cash equivalents at beginning of period	536,533	973,720
Cash and cash equivalents at end of period	$ 625,422	$ 1,061,764
Significant noncash investing and financing activities:		
Accrued capital expenditures	$ 2,306,636	$ 616,093

See accompanying Notes to Consolidated Financial Statements (Unaudited)

6

Table of Contents

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, 2010 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 April 6, 2011.

Note 2 Recent Pronouncements

In January 2010, the FASB issued ASU No. 2010-06, Improving Disclosures about Fair Value Measurements (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06 did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 6 Derivative Instruments and Hedging Activities.

Table of Contents

Note 3 Net (Loss) Income Per Common Share

Net (loss) income per common share basic is calculated by dividing Net (loss) income available to common stockholders by the weighted average number of shares of common stock outstanding during the period. (Loss) income per common share diluted assumes the conversion of all potentially dilutive securities and is calculated by dividing net (loss) income available to common stockholders by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. (Loss) income per common share diluted 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 (Loss) income per common share is as follows:

	2011	2010
Net income	$ 451,079	$ 6,027,152
Accretion of Series A Convertible Redeemable Preferred Stock	(423,143)	
Dividends paid on Series A Convertible Redeemable Preferred Stock	(1,296,418)	
Net (loss) income available to common stockholders	$ (1,268,482)	$ 6,027,152
(Loss) income per common share:		
Net (loss) income available to common stockholders		
Basic	$ (0.03)	$ 0.15
Diluted	$ (0.03)	$ 0.15
Weighted average number of common shares:		
Basic	39,470,284	39,158,985
Add potentially dilutive securities:		
Stock options and non-vested restricted stock		77,859
Diluted	39,470,284	39,236,844

(Loss) income per common share diluted for the three months ended March 31, 2011 excluded the effect of outstanding exercisable options to purchase 1,125,318 shares, 383,222 weighted average restricted shares outstanding, and 4,148,538 shares of Series A Convertible Redeemable Preferred Stock (31,911,830 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options and restricted shares to be anti-dilutive.

Additionally, in accordance with ASC 260, in computing the dilutive effect of convertible securities, Net (loss) income available to common stockholders is also adjusted to add back any convertible preferred dividends and accretion unless the preferred shares are anti-dilutive. As such, there was no add back to Net (loss) income available to common stockholders for the three months ended March 31, 2011 for Accretion of and dividends paid for Series A Convertible Redeemable Preferred Stock of $423,143 and $1,296,418, respectively, in computing (Loss) income per common share diluted as the preferred shares were 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 and remains fully impaired at March 31, 2011.

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 was $0.83 per Mcf for the three months ended March 31, 2011 and 2010.

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.

Table of Contents

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, 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, 2011 and 2010. Future adverse changes could lead to an impairment of all or a portion of our full cost pool in future periods which could significantly reduce earnings during the period in which the impairment occurs, and would result in a corresponding reduction to the full cost pool and stockholders equity.

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, 2011:

Current portion of liability at January 1, 2011	$ 32,893
Add: Long-term asset retirement liability at January 1, 2011	5,465,798
Asset retirement liability at January 1, 2011	5,498,691
Liabilities incurred	8,773
Accretion	135,170
Foreign currency translation	9,269
Asset retirement liability at March 31, 2011	5,651,903
Less: Current portion of liability	(33,832)
Long-term asset retirement liability	$ 5,618,071

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

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. 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.

Table of Contents

Commodity Price Risk and Related Hedging Activities

At March 31, 2011, we had no natural gas collar positions.

At December 31, 2010, we had the following natural gas collar position:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
January through March 2011	360,000	$ 7.45	$ 6.50		775,853

At March 31, 2011, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
April through October 2011	856,000	$ 6.37	1,612,501
April through October 2011	856,000	$ 5.37	753,844
April through October 2011	856,000	$ 5.43	809,378
November 2011 through March 2012	608,000	$ 7.12	1,278,530
November 2011 through March 2012	608,000	$ 6.12	671,109
November 2011 through March 2012	912,000	$ 5.08	68,339
April through October 2012	856,000	$ 5.73	643,577
April through October 2012	1,712,000	$ 4.94	(58,925)
November 2012 through March 2013	604,000	$ 6.42	583,857
November 2012 through March 2013	906,000	$ 5.50	62,164
	8,774,000		$ 6,424,374

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

Period	Volume (MMBtu)	Fixed Price	Fair Value
January through March 2011	360,000	$ 6.67	836,287
January through March 2011	540,000	$ 7.27	1,576,095
April through October 2011	856,000	$ 6.37	1,572,738
April through October 2011	856,000	$ 5.37	715,726
April through October 2011	856,000	$ 5.43	771,155
November 2011 through March 2012	608,000	$ 7.12	1,216,885
November 2011 through March 2012	608,000	$ 6.12	611,002
November 2011 through March 2012	912,000	$ 5.08	(19,449)
April through October 2012	856,000	$ 5.73	653,211
April through October 2012	1,712,000	$ 4.94	(34,286)
November 2012 through March 2013	604,000	$ 6.42	563,413
November 2012 through March 2013	906,000	$ 5.50	35,912
	9,674,000		$ 8,498,689

Table of Contents

Our production is sold at an all-in price which includes the market price for natural gas plus a basis differential . In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the NYMEX contract for the month of sale plus a basis differential of $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. Additionally, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows:

Period	Volume (MMBtu)	Fixed Market Price	Fixed Basis Differential	All-In Price	Gross Sale
April through October 2011	856,000	$ 4.80	$ 0.115	$ 4.915	$ 4,207,240
November 2011 through March 2012	456,000	$ 5.20	$ 0.130	$ 5.330	2,430,480
	1,312,000				$ 6,637,720

The remaining volumes giving effect for the fixed amounts denoted above are as follows:

Period	Volume (MMBtu)	Fixed Basis Differential
April through October 2011	2,568,000	$ 0.115
November 2011 through March 2012	1,976,000	$ 0.130
	4,544,000	

The aforementioned forward physical sale contract is defined as a derivative contract under ASC 815. However, it qualifies for the normal purchase and sale exemption and will not be marked-to-market on the Consolidated Balance Sheets.

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.

At March 31, 2011, we had no interest rate swaps. At December 31, 2010, we had the following interest rate swap:

Description	Effective date	Designated maturity date	Fixed rate(1)	Notional amount	Fair Value
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	$ (4,592)

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

On September 14, 2010, we de-designated the remaining two interest rate swaps which we had previously designated as cash flow hedges under ASC 815-20-25. The de-designation resulted from entering into the Fourth Amended and Restated Credit Agreement (Credit Agreement) which replaced our Third Amended and Restated Credit Agreement. In the new agreement, the notional and interest rates no longer match, and therefore, these two interest rate swaps are no longer effective hedges under ASC 815-20-25. Subsequently, we accounted for the remaining interest rate swaps on a mark-to-market basis which gave rise to both realized and unrealized gains and losses recorded in Interest expense (net of amounts capitalized) in the Consolidated Statements of Operations. Amounts in accumulated other comprehensive income have been frozen and are reclassified into earnings as the forecasted transactions impact earnings. For the three months ended March 31 2010, 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 Credit Agreement and the collateral for the outstanding borrowings under our Credit 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 Credit Agreement.

The application of ASC 820-10-55, 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.

Table of Contents

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 credit risk on the fair value of the assets and liabilities related to the items stated below. The consideration for discounting our counterparties liabilities (our assets) was based on the difference between the S&P credit rating of a comparable company to our counterparties and the 13-week Treasury bill rate, both at the reporting date. The consideration for discounting our liabilities was based on the difference between the market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt. 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, 2011. 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, 2011		**December 31, 2010**		**March 31, 2011**		**December 31, 2010**	
	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)	$	Derivative liability (current)	$
Interest rate swaps	Derivative asset (non-current)		Derivative asset (non-current)		Derivative liability (non-current)		Derivative liability (non-current)	
Total derivatives designated as hedging instruments under ASC 815-20-25		$		$		$		$
Derivatives not designated as hedging instruments under ASC 815-20-25								
Interest rate swaps	Derivative asset (current)	$	Derivative asset (current)	$	Derivative liability (current)	$	Derivative liability (current)	$ 4,592
Natural gas hedge positions	Derivative asset (current)	5,193,701	Derivative asset (current)	7,087,775	Derivative liability (current)		Derivative liability (current)	

Natural gas hedge positions	Derivative asset (non-current)	1,230,673	Derivative asset (non-current)	2,186,767	Derivative liability (non-current)		Derivative liability (non-current)
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 6,424,374		$ 9,274,542		$	$ 4,592

12

Table of Contents

The following (gains) losses on our hedging instruments included in the consolidated statements of operations and other comprehensive income (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, 2011 and 2010

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative 2011	2010
Derivatives designated as hedging instruments under ASC 815-20-25			
Interest rate swaps	Interest expense	$ 17,782	$ 239,214
Total loss		$ 17,782	$ 239,214
Derivatives not designated as hedging instruments under ASC 815-20-25			
Natural gas collar positions	Realized gains on derivative contracts	$ (3,497,062)	$ (1,460,128)
Natural gas collar positions	Unrealized losses (gains) from the change in market value of open derivative contracts	2,850,168	(7,642,042)
Total gain		$ (646,894)	$ (9,102,170)

Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) 2011	2010	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) 2011	2010
Interest rate contracts	$ (206)	$ 30,937	Interest expense	$ (17,782)	$ (239,214)
Total	$ (206)	$ 30,937		$ (17,782)	$ (239,214)

Accumulated comprehensive loss of $1,312,845 as of March 31, 2011 consisted entirely of foreign currency translation adjustments.

Note 7 Long-Term Debt

On September 14, 2010, our Fourth Amended and Restated Credit Agreement (the Credit Agreement) with a group of five banks became effective. The Credit Agreement replaced our Third Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base is determined as of each June and December. The June 2011 borrowing base determination was completed on April 15, 2011 and the borrowing base remains at $90 million. Also on April 15, 2011, the Credit Agreement was amended to remove the minimum Fixed Charge Ratio covenant which was described in our Annual Report on Form 10-K. All outstanding borrowings under the Credit Agreement become due and payable on September 14, 2013. The Credit Agreement provides for interest to accrue at a rate calculated, at the Company s option, at the Adjusted Base Rate plus a margin of 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate) rate plus a margin of 2.75% to 3.25%. Adjusted Base Rate is defined to be the greater of (i) the agent s base rate or (ii) the federal funds rate plus one half of one percent or (iii) the LIBOR Rate plus a margin of 1.00%. In all cases the applicable margin is dependent on the percentage of borrowing base usage. Under the Credit Agreement we are subject to certain financial covenants requiring maintenance of (i) a minimum Current Ratio, (ii) a maximum Debt Ratio, and (iii) a minimum Interest Coverage Ratio. The Current

Ratio of consolidated current assets (defined to include amounts available under our borrowing base) to consolidated current liabilities (defined to exclude up to $1.5 million in accrued and unpaid preferred dividends and the effects, including associated deferred taxes, of unrealized derivative gains and losses) is not permitted to be less than 1.0 to 1.0 as of the end of any fiscal quarter. The Debt Ratio (defined as funded debt at the end of each fiscal quarter to trailing four quarter consolidated EBITDA) at the end of each fiscal quarter cannot exceed 4.5 to 1.0 through the quarter ending June 30, 2011 and 4.0 to 1.0 thereafter. The Interest Coverage Ratio (defined as consolidated EBITDA to consolidated net cash interest expense plus letter of credit fees accruing during the preceding four quarters) cannot be less than 2.75 to 1. Consolidated EBITDA is defined as earnings (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization and also excludes non-recurring charges and other non-cash charges deducted in determining

Table of Contents

net income (loss), which would include unrealized gains and losses from a change in the market value of open derivative contracts. We are also subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. Cash dividends on our preferred stock are permitted if, following any such cash payment our availability is equal to or greater than 15% of the then current borrowing base and our Debt Ratio is less than 3.5 to 1.0. There are no restrictions associated with dividends paid-in-kind on our preferred stock. At March 31, 2011, we are in compliance with the aforementioned Credit Agreement covenants and expect to continue to be in compliance for the 12 months ending March 31, 2012.

As of March 31, 2011, we had $78.5 million of borrowings outstanding under our Credit Agreement, resulting in a borrowing availability of $11.5 million under our $90.0 million borrowing base, subject to compliance with covenants. For the three months ended March 31, 2011 we borrowed $7.2 million and made payments of $9.2 million under the Credit Agreement. For the three months ended March 31, 2010 we borrowed $5.8 million and made payments of $8.1 million under the Credit Agreement. The rates at both March 31, 2011 and December 31, 2010, excluding the effect of our interest rate swaps, were 3.30% per annum. For the three months ended March 31, 2011 and 2010, interest on the borrowings averaged 3.41% and 3.14% per annum, respectively.

The following is a summary of our long-term debt at March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
Borrowings under Credit Agreement	$ 78,500,000	$ 80,500,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured		48,961
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	89,673	93,321
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	337,286	353,880
Total debt	78,926,959	80,996,162
Less current maturities included in current liabilities	(85,706)	(132,743)
Total long-term debt	$ 78,841,253	$ 80,863,419

The fair value of long-term debt at March 31, 2011 and December 31, 2010 was approximately $67.9 million and $68.4 million, 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 market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt.

Note 8 Common Stock

At March 31, 2011 and December 31, 2010, there were 39,858,013 and 39,758,484 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, 2011 and December 31, 2010 were 353,438 and 292,512 shares of restricted stock, respectively.

On January 5, 2011, 98,416 shares of restricted stock were granted in exchange for 566,968 options. For the details related to the Option Exchange , see Note 10 Share-Based Awards.

On March 24, 2011, 819 shares of common stock were purchased by us from two non-executive employees for the payment of $1,335 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, 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.

Table of Contents

Note 9 Series A Convertible Redeemable Preferred Stock

At March 31, 2011 and December 31, 2010, 4,278,124 and 4,148,538 shares of Preferred Stock were issued and outstanding, respectively. At March 31, 2011, an additional 3,123,708 shares of our Preferred Stock are reserved exclusively for the payment of paid-in-kind dividends (PIK dividends). During the three months ended March 31, 2011, the Company declared and issued PIK dividends of 129,586 shares to the holders of Preferred Stock. Additionally, during the three months ended March 31, 2011, cash dividends of $558 were paid for fractional share dividends not paid-in-kind.

The following table details the activity related to the Preferred Stock for the three months ended March 31, 2011:

Balance at December 31, 2010	$ 22,074,320
Accretion of Series A Convertible Redeemable Preferred Stock	423,143
PIK Dividends for Series A Convertible Redeemable Preferred Stock	1,295,860
Other	3,667
Balance at March 31, 2011	$ 23,796,990

There was no Preferred Stock outstanding during the three months ended March 31, 2010.

Note 10 Share-Based Awards

As of March 31, 2011, our 2006 Long-Term Incentive Plan (the 2006 Plan) is our only authorized stock-based award plan. Our 2005 Stock Option Plan was terminated on March 11, 2011 as no options granted under the plan remained outstanding at that time. Our 2006 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 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, 2011, we recorded a compensation expense accrual of $162,867 which was allocated as an addition of $11,787 to lease operating expenses, an addition of $122,112 to general and administrative expense, and $28,968 was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is $545,797 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.16 years.

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.

Option Exchange

On December 7, 2010, we offered our eligible employees the opportunity to exchange certain outstanding stock options for new restricted shares of GeoMet common stock (Restricted Stock), to be granted under the 2006 Plan (Option Exchange). Options eligible for exchange, or eligible options, were those options, whether vested or unvested, that met all of the following requirements:

the options had a per share exercise price greater than $5.00;

the options were granted under one of our existing equity incentive plans;

the options were outstanding and unexercised as of January 5, 2010;

the options were not granted within the twelve-month period immediately preceding the commencement of this offer, December 7, 2010; and

the options did not have a remaining term of less than 12 months immediately following January 5, 2010.

Table of Contents

On January 5, 2011, 98,416 shares of restricted stock were granted to those eligible employees as follows:

Exercise Price Per Share	Number of Eligible Options	Number of New Restricted Shares To Be Granted in Exchange
$5.04	85,122	32,391
$6.98	65,244	993
$7.64	16,000	244
$8.30	247,359	57,287
$10.88	8,265	881
$13.00	144,978	6,620
	566,968	98,416

The Option Exchange was accounted for as a modification of an award in accordance with ASC 718-20-35-3. We recognize the incremental compensation expense of $102,348 over the remaining requisite service period. The incremental compensation expense is the excess of the fair value of the shares of restricted stock granted (using the closing market price) over the fair value of the cancelled options (using the black-scholes model) on January 5, 2011.

Incentive Stock Options

The table below summarizes incentive stock option activity for the three months ended March 31, 2011:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2010	1,391,611	$ 2.85		
Exchanged in Option Exchange	(328,220)	$ 8.41		
Exercised	(1,932)	$ 0.72		
Forfeited	(39,941)	$ 9.24		
Outstanding at March 31, 2011	1,021,518	$ 0.81	5.9	$ 846,688
Options exercisable at March 31, 2011	280,546	$ 0.72	5.0	$ 258,102

The total intrinsic value of incentive stock options exercised during the three months ended March 31, 2011 was $1,526.

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

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2009	997,786	$ 3.95		
Forfeited	(76,878)	$ 1.86		
Outstanding at March 31, 2010	920,908	$ 4.12	4.8	$ 85,873

Options exercisable at March 31, 2010	494,941	$ 5.87	4.0	$ 28,624

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three months ended March 31, 2011:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2010	1,150,548	$ 3.87		
Exchanged in Option Exchange	(238,748)	$ 9.52		
Outstanding at March 31, 2011	911,800	$ 2.39	2.8	$ 95,496
Options exercisable at March 31, 2011	808,000	$ 2.60	2.5	$

Table of Contents

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

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2009	1,400,760	$ 3.61		
Forfeited	(10,212)	$ 0.72		
Outstanding at March 31, 2010	1,390,548	$ 3.63	3.3	$ 17,646
Options exercisable at March 31, 2010	1,114,196	$ 3.05	2.9	$

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the three months ended March 31, 2011:

	Number of Shares	Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2010 `	292,512	$ 3.95
Vested	(37,490)	$ 6.41
Granted in Option Exchange	98,416	$ 1.32
Non-vested restricted stock at March 31, 2011	353,438	$ 2.96

During the three months ended March 31, 2011, 37,490 shares of restricted stock vested with a vesting date fair value of $1.63 per share.

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

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

During the three months ended March 31, 2010, 69,362 shares of restricted stock vested with a vesting date fair value of $0.97 per share.

Note 11 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.

EQT Production Company Claim

In March 2011, we received a letter from EQT Production Company (EQT) stating that our fracturing operations in 2010 had damaged a well owned by EQT, and demanding the payment of the value of the well and other amounts totaling approximately $430,000. In April 2011, EQT revised their demand for payment to approximately $464,000. We are reviewing the claim to determine if we are liable for the damages alleged to have been sustained by EQT. We believe that if we are responsible for the damages, substantially all of the loss will be covered by our insurance. A majority of our proved undeveloped locations in the Pond Creek field are owned by us through a farmout agreement with EQT that provides that if we default under the agreement, our future development rights under the farmout agreement terminate. The failure to pay the amount of any damages to EQT for which we are liable may be a default as defined in the farmout agreement. We do not believe that the payment of any damages to EQT for which we may be liable will have a material impact on our results of operations, financial position nor cash flows.

Environmental and Regulatory

As of March 31, 2011, 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.

Table of Contents

Note 12 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of ASC 740. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

For tax reporting purposes, we have federal and state NOL s of approximately $116.3 million and $125.6 million, respectively, at March 31, 2011 that are available to reduce future taxable income. For tax reporting purposes, we have federal and state NOL s of approximately $113.6 million and $123.0 million, respectively, at December 31, 2010 that are available to reduce future taxable income.

ASC 740 requires the Company to recognize income tax benefits for loss carry forwards that have not previously been recorded. The tax benefits recognized must be reduced by a valuation allowance when it is more likely than not that the deferred tax asset will not be realized. The Company has a net deferred tax asset of $46.0 million as of March 31, 2011 and December 31, 2010, which includes recorded valuation allowances of $3.2 million and $3.1 million, respectively. Our valuation allowances primarily relate to our Canadian operations where we do not believe it is more likely than not that we will recover our net deferred tax asset prior to expiration and have recorded a full valuation allowance as we currently have no proved reserves in Canada. In addition, we have recorded a valuation allowance for certain immaterial state net operating losses where the Company has ceased operations.

Our first material net operating loss (NOL) carryforward expires in 2022 and the last one expires in 2030. We also consider the lengthy carryforward period in the overall evaluation of our ability to realize our NOLs as it substantially increases the likelihood of utilization.

In determining the carrying value of a deferred tax asset, ASC 740 provides for the weighing of evidence in estimating whether and how much of a deferred tax asset may be recoverable. In order to assess the realization of our net deferred tax asset as of March 31, 2011 and December 31, 2010, the Company considered all available negative and positive evidence. While the Company has incurred a cumulative loss over the three year period ended March 31, 2011, after evaluating all available evidence including historical operating results, historical pricing, current operating income, consideration of the full cost ceiling test impairments in 2009 and 2008 that resulted in the cumulative losses, our reserves level as estimated and appraised by an independent third party engineer, future pricing as indicated on the New York Mercantile Exchange, and the length of the carryforward period available, the Company concluded that it is more likely than not the deferred tax asset, net of the $3.2 million valuation allowance related to our Canadian operations and state NOLs, will be realized. The Company will continue to assess the need for additional valuation allowances in the future. If future results are less than projected using either our historical results or our forecast based on the reserve report and future market pricing, then additional valuation allowances may be required to reduce the deferred tax assets which could have a material impact on the Company s results of operations in the period in which it is recorded.

For the three months ended March 31, 2011 and 2010, our effective tax rate was 1.1% and 41.9%, respectively. Our effective tax rate for the three months ended March 31, 2011 was less than the combined estimated federal and state statutory rate of 38% primarily due to a $294,000 net income tax benefit associated with the tender offer exchange of restricted stock for incentive stock options described in Note 10 Share-Based Awards, partially offset by a $62,000 net permanent difference associated with a shortfall related to the vesting of 37,490 shares of restricted stock with a vesting date fair value of $1.63 per share and a grant date fair value of $6.41 per share also described in Note 10 Share-Based Awards and the recording of a valuation allowance against the $46,000 net income tax benefit related to our Canadian operations.

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Statement Regarding Forward-Looking Information

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe, anticipate, estimate, expect, intend, and similar express are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. Certain of these risks are summarized under Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K that we filed with the SEC on April 6, 2011, which you should read carefully in connection with our forward looking statements. 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, 2010, which are included in our 2010 Annual Report on Form 10-K that we filed with the SEC on April 6, 2011.

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 own additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of March 31, 2011, we own a total of approximately 151,000 net acres of coalbed methane and oil and gas development rights.

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 may depend, to a large extent, upon our ability to generate cash flow from operations at or above current levels, maintain borrowing capacity under our Fourth Amended and Restated Credit Agreement (Credit Agreement) at or near current levels, 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 changes in gas prices, our ability to transport our gas to markets, drilling costs, lower than expected production rates 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.

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 Credit 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 Credit Agreement 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.

Current Business Plan

In the current natural gas pricing environment, the Company intends to limit capital spending to its internally generated cash flows from operations. Accordingly, it is unlikely to consider any significant exploration activities until conditions improve, as such investments would likely not produce an acceptable return. We currently intend to drill our proved undeveloped locations in the Pond Creek field and to continue to conduct hydraulic fracturing in new infill wells or in behind pipe shallow zones in the Gurnee field on a

limited basis. Our current focus is to complete the developmental drilling program in the Pond Creek field and, in the Gurnee field, improve production and determine the commerciality of future development through hydraulic fracturing techniques. At current gas prices, it is unlikely that we would seek, nor could we obtain on reasonable terms, significant additional financing necessary to acquire additional properties or otherwise expand beyond our current developmental drilling and hydraulic fracturing programs. At March 31, 2010 and December 31, 2010, we had $11.5 million and $9.5 million, respectively, in available borrowing capacity. This business plan is consistent with our past actions taken in unfavorable pricing environments. For example, when the price of natural gas declined precipitously at the end of 2008, we stopped substantially all of our development activities, and in 2009 did not drill any new wells.

Operational Developments

Pond Creek No new wells were added to sales in the three months ended March 31, 2011. We have a total of 262 net producing wells in the Pond Creek field. Net gas sales were 15.1 MMcf per day for the three months ended March 31, 2011, as compared to 14.4 MMcf per day for the three months ended March 31, 2010. We have revised the number of wells we plan to drill in the Pond Creek field during 2011 from 20 to 16, which will reduce our budgeted expenditures in the field by $2.0 million. We plan to allocate this $2.0 million to operations in our Gurnee field, as discussed below.

In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the NYMEX contract for the month of sale plus $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. Additionally, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows: (1) 4,000 MMBtu /day for the period April 2011 through October 2011 was fixed at a total price for physical gas sales, including the aforementioned basis, of $4.915/ MMBtu and (2) 3,000 MMBtu /day for the period November 2011 through March 2012 was fixed at a total price for physical gas sales, including the aforementioned basis, of $5.33/ MMBtu. If we are unable to fulfill our commitment, or a portion thereof, we are obligated to reimburse our counterparty for any price paid to replace the quantity of natural gas we failed to deliver which is in excess of the contract price. This obligation is limited to the spot price for natural gas at the delivery point on the day we fail to deliver.

Lasher No new wells were added to sales in the three months ended March 31, 2011. Net gas sales averaged 0.44 MMcf per day from 18 producing wells for the three months ended March 31, 2011, as compared to 0.36 MMcf per day for the three months ended March 31, 2010.

Gurnee Net gas sales were 4.8 MMcf per day from a total of 219 producing wells in the Gurnee field for the three months ended March 31, 2011, as compared to 5.3 MMcf per day for the three months ended March 31, 2010. In the third quarter of 2009, we postulated that fracture conductivity loss after commencing production was a main contributor to underperforming production, and that our Gurnee wells were draining only a small area around each wellbore. Since the third quarter of 2009, we have temporarily plugged off production from seven wells and conducted a new shale-like frac technique in upper coal seams that were behind pipe. This technique has generated encouraging results. This technique has also been applied in two existing, previously fraced full wellbores but we were unsuccessful in isolating the existing perforations and these efforts failed. In the fourth quarter of 2010, we drilled a new well in the Gurnee field in order to test this technique on a full wellbore without the complication of existing perforations. This well was completed in the lowest of three coal groups and produced several hundred barrels of water per day and only small volumes of gas for approximately three months before we set a temporary plug above the completion and completed the middle and upper coal groups in the well. We have recently commenced production from this completion and, after a dewatering period, we will remove the plug and produce from all three coal groups in the well. We have recently drilled and completed two additional infill wells to further test this technique. We have recently decided to reallocate approximately $2.0 million of capital expenditures from the Pond Creek field to the Gurnee Field to drill additional wells and complete additional shallow behind pipe coal groups in existing wells.

Garden City We recently put our two horizontal wells back on production and reinstalled a compressor to sell the produced gas. We plan to complete a longer term production test of these wells while temporarily and economically disposing of produced water. We will concurrently be exploring long term solutions to dispose of produced water.

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, 2011.

Table of Contents

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, 2011 and 2010. This table should be read in conjunction with the discussion of the results of operations for the periods presented below (in thousands, except per Mcf amounts).

	Three Months Ended March 31, 2011	2010
Gas sales	$ 7,851	$ 9,884
Lease operating expenses	$ 2,973	$ 3,107
Compression and transportation expenses	916	1,005
Production taxes	322	208
Total production expenses	$ 4,211	$ 4,320
Net sales volumes (MMcf)	1,840	1,820
Pond Creek field	1,362	1,295
Gurnee field	436	474
Per Mcf data ($/Mcf):		
Average natural gas sales price	$ 4.27	$ 5.43
Average natural gas sales price realized(1)	$ 6.17	$ 6.23
Lease operating expenses	$ 1.62	$ 1.71
Pond Creek field	$ 1.23	$ 1.33
Gurnee field	$ 2.74	$ 2.14
Compression and transportation expenses	$ 0.50	$ 0.55
Pond Creek field	$ 0.53	$ 0.58
Gurnee field	$ 0.32	$ 0.37
Production taxes	$ 0.17	$ 0.11
Pond Creek field	$ 0.17	$ 0.18
Gurnee field (2)	$ 0.21	$ (0.07)
Total production expenses	$ 2.29	$ 2.37
Pond Creek field	$ 1.93	$ 2.09
Gurnee field	$ 3.27	$ 2.44
Depletion	$ 0.83	$ 0.83

(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, 2011 compared with Three Months Ended March 31, 2010

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, 2011	2010	Change
	(In thousands)		
Gas sales	$ 7,851	$ 9,884	-21%
Lease operating expenses	$ 2,973	$ 3,107	-4%
Compression expense	$ 608	$ 685	-11%
Transportation expense	$ 308	$ 320	-4%
Production taxes	$ 322	$ 208	55%

Depreciation, depletion and amortization	$ 1,633	$ 1,645	-1%
General and administrative	$ 1,439	$ 1,478	-3%
Realized gains on derivative contracts	$ (3,497)	$ (1,460)	NM
Unrealized losses (gains) from the change in market value of open derivative contracts	$ 2,850	$ (7,642)	NM
Interest expense, net of amounts capitalized	$ (840)	$ (1,244)	-32%
Income tax expense	$ 5	$ 4,354	NM

NM-Not Meaningful

Table of Contents

Gas sales. Gas sales decreased by $2.03 million, or 21%, to $7.85 million compared to the prior year quarter. The decrease in gas sales was a result of decreased gas prices partially offset by increased production. Production increased 1% and average gas prices decreased 21%, excluding hedging transactions. The $2.03 million decrease in gas sales consisted of a $2.14 million decrease in prices and a $0.11 million increase in production.

Lease operating expenses. Lease operating expenses decreased by $0.13 million, or 4%, to $2.97 million compared to the prior year quarter. The decrease in lease operating expenses consisted of a $0.17 million decrease in costs partially offset by a $0.04 million increase in production. The $0.17 million decrease in costs was primarily due to the shut-in of our Peace River field in British Columbia effective April 2010.

Compression expense. Compression expense decreased by $0.08 million, or 11%, to $0.61 million compared to the prior year quarter. The $0.08 million decrease was comprised of a $0.09 million decrease in costs partially offset by a $0.01 million increase in production. The decrease in compression expense was primarily due to the shutting-in of our Peace River field in British Columbia effective April 2010 and the exercise of early buyout options on two leased compressors in November 2010.

Transportation expense. Transportation expense decreased by $0.01 million, or 4%, to $0.31 million compared to the prior year quarter. The $0.01 million decrease was primarily due to a refund of over-charged pipeline penalties.

Production taxes. Production taxes increased by $0.11 million, or 55%, to $0.32 million compared to the prior year quarter. The $0.11 million increase in production taxes was primarily due to a refund received in March 2010 for production taxes related to our Gurnee field.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $0.01 million, or 1%, to $1.63 million compared to the prior year quarter. The depreciation, depletion and amortization decrease consisted of a $0.03 million decrease in the depletion rate partially offset by a $0.02 million increase in production.

General and administrative. General and administrative expenses decreased by $0.04 million, or 3%, to $1.44 million compared to the prior year quarter. The decrease in general and administrative expenses was primarily due to the continued focus on our company-wide cost reduction strategy.

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $2.04 million, or 140%, to $3.50 million compared to the prior year quarter. Realized gains represent net cash flow settlement paid to us from the counterparty, while realized losses represent net cash flow settlements paid to the counterparty. Realized gains occur when natural gas prices go below the derivative floor prices. Conversely, realized losses occur when natural gas prices exceed the derivative ceiling prices.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts were $2.85 million compared to unrealized gains of $7.64 million in 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 loss was a result of the decreased estimated fair value of our natural gas derivative contracts resulting from the increase in natural gas prices over the course of the first quarter of 2011.

Interest expense. Interest expense decreased by $0.40 million, or 32%, to $0.84 million compared to the prior year quarter. The decrease was primarily due to a lower average outstanding revolver balance in the current year quarter combined with a $0.24 million loss on our interest rate swaps in the prior year quarter, partially offset by a higher average interest rate on our revolving credit facility in the current year quarter.

Income tax expense. Income tax expense was $0.01 million in the current year period. The effective tax rate for the period was 1.1%. Our effective tax rate differs from the estimated federal and state statutory rate of 38% primarily due to a $294,000 net income tax benefit associated with the tender offer exchange of restricted stock for incentive stock options described in Note 10 Share-Based Awards, partially offset by a $62,000 net permanent difference associated with a shortfall related to the vesting of 37,490 shares of restricted stock with a vesting date fair value of $1.63 per share and a grant date fair value of $6.41 per share also described in Note 10 Share-Based Awards and the recording of a valuation allowance against the $46,000 net income tax benefit related to our Canadian operations.

Table of Contents

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the three months ended March 31, 2011 and 2010 were $3.9 million and $4.7 million, respectively. Cash flows from operations of $3.9 million for the three months ended March 31, 2011 were sufficient to fund net cash used in investing activities of $1.8 million, which primarily includes capital expenditures for the development of our gas properties, and cash used in financing activities of $2.1 million, primarily related to credit facility net repayment. As of March 31, 2011 and 2010, we had working capital of approximately $0.3 million and $3.7 million, respectively. Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our Credit Agreement or various financing alternatives will provide us with sufficient capital resources to meet our projected operational and capital expenditure needs for the next twelve months.

We expect our remaining capital expenditure budget for 2011 to be $12.6 million. The amount and timing of our expenditures are subject to change based upon market conditions, natural gas prices, 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 changes in borrowing capacity under our Credit Agreement.

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

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued or prolonged low natural gas prices may also result in non-compliance with the covenants in our Credit 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 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.

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. 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.

Table of Contents

Commodity Price Risk and Related Hedging Activities

At March 31, 2011, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
April through October 2011	856,000	$ 6.37	1,612,501
April through October 2011	856,000	$ 5.37	753,844
April through October 2011	856,000	$ 5.43	809,378
November 2011 through March 2012	608,000	$ 7.12	1,278,530
November 2011 through March 2012	608,000	$ 6.12	671,109
November 2011 through March 2012	912,000	$ 5.08	68,339
April through October 2012	856,000	$ 5.73	643,577
April through October 2012	1,712,000	$ 4.94	(58,925)
November 2012 through March 2013	604,000	$ 6.42	583,857
November 2012 through March 2013	906,000	$ 5.50	62,164
	8,774,000		$ 6,424,374

Our production is sold at an all-in price which includes the market price for natural gas plus a basis differential . In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the NYMEX contract for the month of sale plus a basis differential of $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. Additionally, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows:

Period	Volume (MMBtu)	Fixed Market Price	Fixed Basis Differential	All-In Price	Gross Sale
April through October 2011	856,000	$ 4.80	$ 0.115	$ 4.915	$ 4,207,240
November 2011 through March 2012	456,000	$ 5.20	$ 0.130	$ 5.330	2,430,480
	1,312,000				$ 6,637,720

The remaining volumes giving effect for the fixed amounts denoted above are as follows:

Period	Volume (MMBtu)	Fixed Basis Differential
April through October 2011	2,568,000	$ 0.115
November 2011 through March 2012	1,976,000	$ 0.130
	4,544,000	

The aforementioned forward physical sale contract is defined as a derivative contract under ASC 815. However, it qualifies for the normal purchase and sale exemption and will not be marked-to-market on the Consolidated Balance Sheets (Unaudited).

Capital Expenditures and Capital Resources

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

	Three Months Ended March 31, 2011	2010
Capital expenditures:		
Leasehold acquisition	$ 350,564	$ 129,159
Exploration	3,000	
Development	2,499,765	1,364,121
Other items (primarily capitalized overhead and interest)	273,158	160,836
Total capital expenditures	$ 3,126,487	$ 1,654,116

We expect our remaining capital expenditure budget for 2011 to be $12.6 million and 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 Credit Agreement.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. There has been no material changes in those commitments disclosed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Commitments of our 2010 Annual Report on Form 10-K that we filed with the SEC on April 6, 2011.

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, 2011, a 10% decrease in the prices received for natural gas production would have had an approximate $0.8 million impact on our revenues, which would have been offset by approximately $0.5 million realized 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, 2011, we had $78.5 million outstanding under our Credit Agreement. For the three months ended March 31, 2011 and 2010, interest on the borrowings averaged 3.41% per annum and 3.14% per annum, respectively. Borrowing availability at March 31, 2011 was $10.5 million. All of the debt outstanding under our Credit Agreement 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 Credit Agreement at March 31, 2011, a 1% increase in market interest rates would have increased interest expense and negatively impacted our cash flows for the three months ended March 31, 2011 by approximately $0.2 million.

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. 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, 2011 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.

Table of Contents

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.

Table of Contents

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.

EQT Production Company Claim

In March 2011, we received a letter from EQT Production Company (EQT) stating that our fracturing operations in 2010 had damaged a well owned by EQT, and demanding the payment of the value of the well and other amounts totaling approximately $430,000. In April 2011, EQT revised their demand for payment to approximately $464,000. We are reviewing the claim to determine if we are liable for the damages alleged to have been sustained by EQT. We believe that if we are responsible for the damages, substantially all of the loss will be covered by our insurance. A majority of our proved undeveloped locations in the Pond Creek field are owned by us through a farmout agreement with EQT that provides that if we default under the agreement, our future development rights under the farmout agreement terminate. The failure to pay the amount of any damages to EQT for which we are liable may be a default as defined in the farmout agreement. We do not believe that the payment of any damages to EQT for which we may be liable will have a material impact on our results of operations, financial position nor cash flows.

Environmental and Regulatory

As of March 31, 2011, 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, 2010.

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.

Table of Contents

SIGNATURES

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

GeoMet, Inc.

Date: May 6, 2011

By /S/ WILLIAM C. RANKIN

William C. Rankin, Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

28

Table of Contents

INDEX TO EXHIBITS

Exhibit Number	Exhibits
10.1*	First Amendment to Fourth Amended and Restated Credit Agreement dated April 15, 2011 by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. National Bank Association, and Sterling Bank.
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