GeoMet, Inc.
Form 10-Q
May 15, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2013

OR

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

For the transition period from to

Commission File Number 001-32960

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 o 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). x Yes o 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 o	Accelerated filer o
Non-accelerated filer o	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). o Yes x No

As of May 1, 2013, 40,689,486 shares and 5,471,610 shares, respectively, of the registrant s common stock and preferred stock, par value $0.001 per share, were outstanding.

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Part I. FINANCIAL INFORMATION

Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,382,319	$ 7,234,225
Accounts receivable, net of allowance of $14,744 and $17,634 at March 31, 2013 and December 31, 2012, respectively	4,514,157	6,248,819
Inventory	269,569	262,885
Derivative asset natural gas contracts		3,929,767
Other current assets	1,233,779	1,437,819
Total current assets	13,399,824	19,113,515
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	539,151,397	539,077,119
Other property and equipment	3,663,310	3,749,621
Total property and equipment	542,814,707	542,826,740
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(469,153,061)	(467,702,053)
Property and equipment net	73,661,646	75,124,687
Other noncurrent assets:		
Deferred income taxes		1,125,804
Other	795,773	962,451
Total other noncurrent assets	795,773	2,088,255
TOTAL ASSETS	$ 87,857,243	$ 96,326,457
LIABILITIES, MEZZANINE AND STOCKHOLDERS DEFICIT		
Current Liabilities:		
Accounts payable	$ 3,247,634	$ 5,728,879
Royalties payable	3,537,344	3,830,904
Accrued liabilities	3,501,872	1,793,946
Deferred income taxes		1,125,804
Derivative liability natural gas contracts	5,543,501	919,572
Asset retirement obligations	43,851	73,706
Current portion of long-term debt	5,800,000	10,300,000
Total current liabilities	21,674,202	23,772,811
Long-term debt	129,000,000	129,000,000
Asset retirement obligations	13,542,331	13,235,318
Derivative liability natural gas contracts	1,717,523	1,636,348
Other long-term accrued liabilities	136,120	143,682
TOTAL LIABILITIES	166,070,176	167,788,159
Commitments and contingencies (Note 16)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,660,435; redemption amount $53,058,650; $.001 par value; 7,401,832 shares authorized,	36,345,424	35,851,887

5,305,865 shares were issued and outstanding at March 31, 2013 and December 31, 2012				
Stockholders Deficit:				
Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued				
Common stock, $0.001 par value authorized 125,000,000 shares; 40,689,486 and 40,690,077 issued and outstanding at March 31, 2013 and December 31, 2012, respectively		40,689		40,690
Treasury stock 10,432 shares at March 31, 2013 and December 31, 2012		(94,424)		(94,424)
Paid-in capital		193,522,720		195,033,585
Accumulated other comprehensive loss		(31,725)		(53,020)
Retained deficit		(307,812,410)		(302,057,496)
Less notes receivable		(183,207)		(182,924)
Total stockholders deficit		(114,558,357)		(107,313,589)
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS DEFICIT	$	87,857,243	$	96,326,457

See accompanying Notes to Audited Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

FOR THE THREE MONTHS ENDED MARCH 31,

		2013		2012
Revenues:				
Gas sales	$	10,879,264	$	10,143,174
Other		44,956		75,765
Total revenues		10,924,220		10,218,939
Expenses:				
Lease operating expense		4,469,239		4,441,434
Compression and transportation expense		1,838,636		2,239,488
Production taxes		550,546		469,649
Depreciation, depletion and amortization		1,506,366		3,630,469
Impairment of gas properties				15,779,441
General and administrative		998,233		1,302,025
Restructuring costs		70,188		
Losses (gains) on natural gas derivatives		5,535,119		(10,017,080)
Total operating expenses		14,968,327		17,845,426
Operating loss		(4,044,107)		(7,626,487)
Other income (expense):				
Interest income		420		3,702
Interest expense		(1,676,329)		(1,275,844)
Other		(28,648)		(4,352)
Total other income (expense):		(1,704,557)		(1,276,494)
Loss before income taxes from continuing operations		(5,748,664)		(8,902,981)
Income tax expense		6,250		44,024,450
Loss from continuing operations		(5,754,914)		(52,927,431)
Discontinued operations				(20,573)
Net loss	$	(5,754,914)	$	(52,948,004)
Accretion of discount on Series A Convertible Redeemable Preferred Stock		(493,537)		(462,016)
Paid-in-kind dividends on Series A Convertible Redeemable Preferred Stock		(1,075,685)		(1,240,720)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock		(633)		(645)
Net loss available to common stockholders	$	(7,324,769)	$	(54,651,385)
Net loss per common share basic:				
Net loss per common share from continuing operations	$	(0.18)	$	(1.37)
Net loss per common share from discontinued operations	$		$	
Net loss per common share basic	$	(0.18)	$	(1.37)
Net loss per common share diluted:				
Net loss per common share from continuing operations	$	(0.18)	$	(1.37)
Net loss per common share from discontinued operations	$		$	
Net loss per common share diluted	$	(0.18)	$	(1.37)
Weighted average number of common shares:				
Basic		40,456,773		39,748,005
Diluted		40,456,773		39,748,005

See accompanying Notes to Audited Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS (UNAUDITED)

FOR THE THREE MONTHS ENDED MARCH 31,

	2013	2012
Net loss	$ (5,754,914)	$ (52,948,004)
Other comprehensive income (loss), net of related taxes:		
Foreign currency translation adjustment	1,232	(7,451)
Unrealized gain on available for sale securities	20,063	
Comprehensive loss	$ (5,733,619)	$ (52,955,455)

See accompanying Notes to Audited Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

FOR THE YEARS ENDED DECEMBER 31,

	Three Months Ended March 31, 2013	2012
Cash flows provided by operating activities:		
Net loss	$ (5,754,914)	$ (52,948,004)
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	1,506,366	3,629,341
Impairment of gas properties		15,779,441
Amortization of debt issuance costs	225,870	161,606
Deferred income tax		44,018,200
Unrealized losses (gains) from the change in market value of open derivative contracts	8,634,871	(5,224,211)
Stock-based compensation	58,724	114,756
Loss on sale of other assets	27,616	5,200
Accretion expense	317,013	196,210
Changes in operating assets and liabilities:		
Accounts receivable	1,734,662	50,145
Other current assets	163,260	56,512
Accounts payable	(2,682,655)	543,641
Other accrued liabilities	584,823	142,019
Net cash provided by operating activities	4,815,636	6,524,856
Cash flows (used in) provided by investing activities:		
Capital expenditures	(172,466)	(292,316)
Return of original basis through the settlement of natural gas derivative contracts		2,544,230
Proceeds from sale of other assets	9,375	3,500
Other assets		10,049
Net cash (used in) provided by investing activities	(163,091)	2,265,463
Cash flows used in financing activities:		
Proceeds from borrowings under Credit Agreement		7,400,000
Repayment of borrowings under Credit Agreement	(4,500,000)	(15,800,000)
Deferred financing costs	(3,801)	(32,843)
Payments on other debt		(22,166)
Dividends paid	(633)	(645)
Treasury stock	(17)	(1,862)
Net cash used in financing activities	(4,504,451)	(8,457,516)
Effect of exchange rate changes on cash		507
Increase in cash and cash equivalents	148,094	333,310
Cash and cash equivalents at beginning of period	7,234,225	457,865
Cash and cash equivalents at end of period	$ 7,382,319	$ 791,175
Supplemental disclosure of cash flow information:		
Cash paid during the period for:		

Interest expense	$	1,664,956	$	1,369,617
Income taxes	$	6,250	$	6,250
Significant noncash investing and financing activities:				
Accrued capital expenditures	$	357,856	$	840,226

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet, Company, we, or our) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba and Black Warrior Basins in Alabama and the central Appalachian Basin in Virginia and West Virginia. We also own additional coalbed methane and oil and gas development rights, principally in Alabama, Virginia, and West Virginia.

Note 2 Sale of Coalbed Methane Properties in Alabama

On May 3, 2013, the Company entered into a purchase and sale agreement (PSA) to sell its coalbed methane properties in Alabama to Saga Resource Partners LLC, for a purchase price of $63.2 million, subject to customary purchase price adjustments. The effective date of this transaction is April 1, 2013, and it is expected to close on or before June 14, 2013, subject to the exercise of preferential rights and customary closing conditions. GeoMet plans to use the cash proceeds from this asset divestiture, net of purchase price adjustments and other transaction related expenditures, to repay borrowings under its Credit Agreement. We have estimated no material income tax impact on the gain resulting from the sale due to offsetting operating losses.

In connection with the PSA to sell the coalbed methane properties in Alabama, on May 1, 2013, the Company and the lenders under its Fifth Amended and Restated Credit Agreement executed the Fifth Amendment to such agreement (Amendment), which became effective as of May 1, 2013 and provides the necessary consents to sell the coalbed methane properties in Alabama. The Amendment requires repayment of a minimum of $52 million of borrowings which will result in the elimination of the non-conforming tranche B portion of total outstanding borrowings. Following the expected use of net proceeds for repayment of indebtedness, GeoMet s borrowing base will be the lesser of $83 million or actual outstanding borrowings at such time.

GeoMet s average net interest in the coalbed methane properties in Alabama being sold produced approximately 9,700 Mcf of natural gas per day during the month of March 2013, or approximately 29% of GeoMet s total production for this time period. As of March 31, 2013 and based on Securities and Exchange Commission guidelines, GeoMet s net proved reserves attributable to the coalbed methane properties in Alabama being sold were estimated to be approximately 43 Bcf, all classified as proved developed reserves.

Note 3 Going Concern and Management s Plans

The accompanying consolidated financial statements (unaudited) have been prepared in conformity with accounting principles generally accepted in the United States which contemplate continuation of the Company as a going concern. In 2012, the amounts outstanding under the Company s Fifth Amended and Restated Credit Agreement (Credit Agreement) exceeded the borrowing base as determined by the lenders under the Credit Agreement. In August 2012, the Company amended the Credit Agreement to provide for a conforming tranche limited to the borrowing base, and a non-conforming tranche in the amount outstanding in excess of the borrowing base. The Company is required to dedicate substantially all of its free cash flow to repayment of the non-conforming tranche. The Credit Agreement matures on April 1, 2014, and no assurances can be made that the Company will be able to refinance, repay or further extend the maturity date of the Credit Agreement. The borrowing base deficiency also adversely impacted the Company s working capital by reclassifying the next twelve months required payments from Long-term debt to Current Liabilities in the Consolidated Balance Sheets (Unaudited) as of March 31, 2013. In addition, as of March 31, 2013, the Company had a working capital deficit of $8.3 million, a retained deficit of $307.8 million and stockholders deficit of $114.6 million. Depressed natural gas prices in 2012 resulted in significant property impairments and full valuation of our deferred tax assets during 2012. On April 2, 2013, all the indebtedness under the Company s Credit Agreement was reclassified to current liabilities. These and other factors raise substantial doubt about the Company s ability to continue as a going concern.

Management s current business plan is primarily focused on eliminating the borrowing base deficiency, maintaining compliance with the Credit Agreement, as amended, maintaining production levels and controlling costs. In addition, management recently executed a purchase and sale agreement for all of the Company s coalbed methane properties in Alabama described above in Footnote 2 Sale of Coalbed Methane Properties in Alabama that were being marketed for sale by an asset divestiture firm. Management will continue to evaluate the viability of additional asset sales or strategic corporate transactions. There can be no assurance that the Company will be able to sell properties (including under the existing PSA), to effect a strategic transaction, or realize adequate proceeds from the sale of properties to eliminate the deficiency under, or to refinance, the Credit Agreement.

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The ability of the Company to continue as a going concern is dependent upon its ability to generate sufficient cash flows and sales proceeds or other sources of capital sufficient to repay or refinance its indebtedness, continue its operations and fund its long-term capital needs. The accompanying consolidated financial statements do not include any adjustments that might be necessary if the Company is unable to continue as a going concern.

Note 4 Recent Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board (FASB), issued Accounting Standards Update (ASU), No. 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date. ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations addressed within existing guidance. The update is effective for interim and annual periods beginning after December 15, 2013 and is required to be applied retrospectively to all prior periods presented for those obligations that existed upon adoption of ASU 2013-04. We are presently assessing the potential impact of ASU 2013-04.

In February 2013, the FASB issued Accounting Standards Update (ASU) No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. The update requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under accounting principles generally accepted in the United States (GAAP) to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. The amendments are effective prospectively for reporting periods beginning after December 15, 2012 The Company has adopted and applied the provisions of ASU 2012-02 which did not impact its operating results, financial position or cash flows.

In January 2013, the FASB issued ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in this update clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company has adopted and applied the provisions of ASU 2013-01. As the Company currently presents unrealized gains (losses) on commodity derivatives on a gross basis on our Consolidated Balance Sheets (Unaudited), no material impact was noted.

In July 2012, the FASB issued ASU 2012-02, which amends the guidance in ASC 350-30 on testing indefinite-lived intangible assets, other than goodwill, for impairment. The FASB issued the ASU in response to feedback on ASU 2011-08, which amended the goodwill impairment testing requirements by allowing an entity to perform a qualitative impairment assessment before proceeding to the two- step impairment test. Similarly, under ASU 2012-02, an entity testing an indefinite-lived intangible asset for impairment has the option of performing a qualitative assessment before calculating the fair value of the asset. Although ASU 2012-02 revises the examples of events and circumstances that an entity should consider in interim periods, it does not revise the requirements to test indefinite-lived intangible assets (1) annually for impairment and (2) between annual tests if there is a change in events or circumstances. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. The Company has adopted and applied the provisions of ASU 2012-02 which did not impact its operating results, financial position or cash flows.

Note 5 Discontinued Operations

On June 20, 2012, we disposed of Hudson s Hope Gas, Ltd., a subsidiary which held our Canadian gas properties, in exchange for two million shares of Canada Energy Partners, Inc. (CEP Shares) which we are restricted from selling before June 20, 2013. We recognized a loss on the disposition in the amount of $0.7 million, which was made up of a $1.3 million loss related to the currency translation adjustment, offset by $0.3 million in asset retirement obligations conveyed to the buyer and the proceeds consisting of the $0.3 million in estimated fair value of the CEP shares received. The loss on this disposition has been included in Discontinued operations, net of tax, in the Consolidated Statements of Operations (Unaudited). Additionally, all historical operating results related to the disposed company have been removed from Operating (loss) income and included in Discontinued operations, net of tax, in the Consolidated Statements of Operations (Unaudited) for the periods presented.

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As a result of the disposition, we are classifying these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations for the three months ended March 31, 2013 and 2012 were as follows:

	2013	2012
Revenues	$	$
Operating expenses		20,549
Operating loss		(20,549)
Loss on sale of Hudson s Hope Gas, Ltd.		
Other expense		(24)
Income tax expense		
Net income (loss)	$	$ (20,573)

Note 6 Net Loss Per Common Share

Net Loss Per Share of Common Stock Net loss per common share basic is calculated by dividing Net loss available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Net loss per common share diluted assumes the conversion of all potentially dilutive securities and is calculated by dividing Net loss available to common stockholders by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Net loss 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 shares of common stock would have an anti-dilutive effect. A reconciliation of the numerator and denominator for the three months ended March 31, 2013 and 2012 is as follows:

	2013	2012
Net loss available to common stockholders	$ (7,324,769)	$ (54,651,385)
Net loss per common share basic:		
Net loss per common share from continuing operations	$ (0.18)	$ (1.37)
Net loss per common share from discontinued operations	$	$
Net loss per common share basic	$ (0.18)	$ (1.37)
Net loss per common share diluted:		
Net loss per common share from continuing operations	$ (0.18)	$ (1.37)
Net loss per common share from discontinued operations	$	$
Net loss per common share diluted	$ (0.18)	$ (1.37)
Weighted average number of common shares:		
Basic	40,456,773	39,748,005
Diluted	40,456,773	39,748,005

Net loss per common share diluted for the three months ended March 31, 2013 excluded the effect of outstanding exercisable options to purchase 2,365,466 shares, 233,099 weighted average restricted shares outstanding, and 5,305,865 shares of Series A Convertible Redeemable Preferred Stock (40,814,346 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 computing the dilutive effect of convertible securities, Net loss 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 available to common stockholders for the three months ended March 31, 2013 for Accretion of and dividends paid for Series A Convertible Redeemable Preferred Stock of $493,537 and $1,076,318, respectively, in computing Net loss per common share diluted as the preferred shares were anti-dilutive.

Net loss per common share diluted for the three months ended March 31, 2012 excluded the effect of outstanding exercisable options to purchase 1,384,398 shares, 262,896 weighted average restricted shares outstanding, and 4,549,537 shares of Series A Convertible Redeemable Preferred Stock (34,996,440 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 computing the dilutive effect of convertible securities, Net loss available to common stockholders is also

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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 available to common stockholders for the three months ended March 31, 2012 for Accretion of and dividends paid for Series A Convertible Redeemable Preferred Stock of $462,016 and $1,241,365, respectively, in computing Net loss per common share diluted as the preferred shares were anti-dilutive.

Note 7 Gas Properties

The method of accounting for oil and gas producing activities determines which costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for our gas properties. Under this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized.

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.

Estimation of proved gas reserves involves 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. 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 stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. In addition, 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.

For the twelve months ended March 31, 2013, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.97 per Mcf, resulting in a natural gas price of $3.03 per Mcf when adjusted for regional price differentials. Based on the ceiling test performed utilizing the aforementioned prices, no write-down of the carrying value of our U.S. full cost pool was required at March 31, 2013.

For the twelve months ended March 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.75 per Mcf, resulting in a natural gas price of $3.90 per Mcf when adjusted for regional price differentials. Based on the ceiling test performed utilizing the aforementioned prices, we recorded a $15.8 million write-down of the carrying value of our U.S. full cost pool at March 31, 2012.

Note 8 Asset Retirement Obligations

We record an asset retirement obligation (ARO) in the Consolidated Balance Sheets (Unaudited) 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 the abandonment obligation was incurred using an assumed cost of funds for GeoMet. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed cost of funds. Periodically, we update the cost assumptions resulting from market changes and revise the liability recorded accordingly.

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The following table details the changes to our asset retirement liability for the three months ended March 31, 2013:

Current portion of liability at January 1, 2013	$	73,706
Add: Long-term asset retirement liability at January 1, 2013		13,235,318
Asset retirement liability at January 1, 2013		13,309,024
Settlements		(39,855)
Accretion		317,013
Asset retirement liability at March 31, 2013		13,586,182
Less: Current portion of liability		(43,851)
Long-term asset retirement liability	$	13,542,331

Note 9 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 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. Our Credit Agreement limits amounts of future natural gas production that we may hedge. At March 31, 2013, we do not have the ability to enter into additional natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

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 (Unaudited) and Consolidated Statements of Operations (Unaudited).

Commodity Price Risk and Related Hedging Activities

At March 31, 2013, we had the following natural gas collar positions:

Period

	Volume (MMBtu)		Sold Ceiling		Bought Floor		Fair Value
January 2014 through December 2015	3,650,000	$	4.30	$	3.60	$	(904,032)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50		(1,141,532)
	7,300,000					$	(2,045,564)

At December 31, 2012, we had the following natural gas collar positions:

Period	Volume (MMBtu)		Sold Ceiling		Bought Floor		Fair Value
January 2014 through December 2015	3,650,000	$	4.30	$	3.60	$	(556,636)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50		(796,266)
	7,300,000					$	(1,352,902)

At March 31, 2013, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
April 2013 through March 2014	2,920,000	$	3.81		(1,044,483)
April 2013 through March 2014	2,920,000	$	3.82		(1,016,450)
April 2013 through December 2013	1,650,000	$	3.60		(832,643)
April 2013 through December 2013	2,750,000	$	3.25		(2,321,884)
	10,240,000			$	(5,215,460)

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At December 31, 2012, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
January through March 2013	360,000	$	6.42		1,100,395
January through March 2013	540,000	$	5.50		1,156,734
January 2013 through March 2014	3,640,000	$	3.81		613,675
January 2013 through March 2014	3,640,000	$	3.82		648,264
January 2013 through December 2013	2,190,000	$	3.60		127,253
April 2013 through December 2013	2,750,000	$	3.25		(919,572)
	13,120,000			$	2,726,749

At December 31, 2012, we had the following forward sales at NYMEX plus a fixed basis:

Period	Volume (MMBtu)		Fixed Basis
January through March 2013	450,000	$	0.19
January through March 2013	918,000	$	0.22
	1,368,000		

The aforementioned forward physical sale contracts qualified for normal purchase and sale exemption and, as such, we have elected not to record it on the Consolidated Balance Sheets (Unaudited) using mark-to-market accounting.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants or affiliates of the 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.

We estimate the fair value of our natural gas derivative contracts and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. 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.

In order to estimate the fair value of our natural gas derivative contracts, 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.

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, 2013. Based on the use of observable market inputs, we have designated these types of instruments designated below as Level 2. The fair value of our Level 2 derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	March 31, 2013		December 31, 2012		March 31, 2013		December 31, 2012	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives not designated as hedging instruments								
Natural gas hedge positions	Derivative asset (current)	$	Derivative asset (current)	$ 3,929,767	Derivative liability (current)	$ 5,543,501	Derivative liability (current)	$ 919,572
Natural gas hedge positions	Derivative asset (non-current)		Derivative asset (non-current)		Derivative liability (non-current)	1,717,523	Derivative liability (non-current)	1,636,348
Total derivatives not designated as hedging instruments		$		$ 3,929,767		$ 7,261,024		$ 2,555,920

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The following losses (gains) on our hedging instruments included in the Consolidated Statements of Operations (Unaudited) for the three months ended March 31, 2013 and 2012 are as follows:

Derivatives not designated as hedging instruments	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative 2013		Amount of (Gain) or Loss Recognized in Income on Derivative 2012	
Natural gas collar/swap settled positions	Losses (gains) on natural gas derivatives	$	(3,099,752)	$	(4,792,869)
Natural gas collar/swap unsettled positions	Losses (gains) on natural gas derivatives		8,634,871		(5,224,211)
Total gain		$	5,535,119	$	(10,017,080)

Note 10 Investment in Canada Energy Partners

At March 31, 2013 and December 31, 2012, we own two million shares of Canada Energy Partners (CEP), discussed in Note 5 Discontinued Operations, which we classify as available for sale and record at fair value in Other noncurrent assets on the Consolidated Balance Sheets (Unaudited) based on the closing price of the shares on the TSX Venture Exchange on that date. Gains or losses related to both market price fluctuation and currency translation adjustment on the shares of CEP are held in Accumulated other comprehensive loss in the Consolidated Balance Sheets (Unaudited). At March 31, 2013 and December 31, 2012, the value of the shares recorded in Other noncurrent assets was $262,044 and $240,749, respectively, using a Level 1 input. Accumulated other comprehensive loss of $31,725 in the Consolidated Balance Sheets (Unaudited) as of March 31, 2013 consisted of a $41,599 cumulative decrease in market value offset by a $9,874 cumulative gain related to currency translation on the CEP shares. Accumulated other comprehensive loss of $53,020 in the Consolidated Balance Sheets (Unaudited) as of December 31, 2012 consisted of a $61,661 cumulative decrease in market value offset by a $8,641 cumulative gain related to currency translation on the CEP shares.

Note 11 Long-Term Debt

Under our Credit Agreement, outstanding borrowings may not exceed a borrowing base determined by the lenders. During 2012, the amounts borrowed under our Credit Agreement exceeded the borrowing base. On August 8, 2012, in connection with the excess of borrowings over the borrowing base, we amended the Credit Agreement. Borrowings under the Credit Agreement at August 8, 2012 totaled $148.6 million. The Credit Agreement, as amended, provided for a tranche A loan in the amount of our borrowing base and a tranche B loan in the amount of the excess. The borrowing base, determined as of May 1, 2012, is currently $115.0 million. The tranche B loan was $21.8 million as of March 1, 2013. The borrowing base will be re-determined as of each June and December with the next determination scheduled to be completed by December 15, 2013. Upon any re-determination of the borrowing base, the re-determined amount of the conforming borrowing base will constitute a new tranche A loan, with any decrease in tranche A causing an automatic corresponding increase in tranche B, subject to certain limitations described below, and any increase in tranche A causing an automatic corresponding decrease in tranche B. At the next and any subsequent borrowing base determination, tranche B may not increase by more than 25% of the amount of the principal payments made on tranche B loans since the prior redetermination of the borrowing base. If a future determination of the borrowing base results in the outstanding amount of the tranche B loan exceeding the amount permitted under the Credit Agreement, we have 30 days to repay such excess. The Credit Agreement no longer provides for loans to be available on a revolving basis up to the amount of the borrowing base. As a result, the current outstanding loans, once repaid, may not be re-borrowed by the Company. All outstanding borrowings under the Credit Agreement are due and payable on April 1, 2014. In addition, the Credit Agreement obligates us to reduce our borrowings monthly by substantially all of our available excess cash flow. The Credit Agreement provides for interest to accrue at a rate calculated, at our option, at the Adjusted Base Rate plus a margin of 2.00% on tranche A loans and 4.00% on tranche B loans or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 3.00% on tranche A loans and 5.00% on tranche B loans. 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%. The Credit Agreement requires an additional payment to the lenders based on the amount of tranche B loans as follows:

Calculation Date	Fee Amount (basis points)	Date Payable
5/25/2013	125 bps	6/1/2013
8/25/2013	150 bps	9/1/2013
11/25/2013	175 bps	12/1/2013

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All financial covenants were deleted by the Amendment and were replaced with a capital expenditure covenant (a maximum of $1.5 million in 2012 and $1.0 million in 2013) and a maximum debt covenant as follows:

Quarter Ending		**Maximum Principal Outstanding**
3/31/2013	$	136,000,000
6/30/2013	$	132,700,000
9/30/2013	$	131,500,000
12/31/2013	$	129,000,000

As of March 31, 2013, we had $134.8 million of borrowings outstanding under our Credit Agreement. As of March 31, 2013, the interest rates applied to borrowings under tranche A and tranche B were 3.20% and 5.39%, respectively. As of December 31, 2012, interest rates applied to borrowings under tranche A and tranche B were 3.21% and 5.21%, respectively. For the three months ended March 31, 2013, we had no borrowings and made payments of $4.5 million under the Credit Agreement. For the three months ended March 31, 2012, we borrowed $7.4 million and made payments of $15.8 million under the Credit Agreement. For the three months ended March 31, 2013 and 2012, interest on the borrowings averaged 4.27% and 2.90% per annum, respectively.

The following is a summary of our long-term debt at March 31, 2013 and December 31, 2012:

		March 31, 2013		**December 31, 2012**
Borrowings under Credit Agreement:				
Tranche A	$	115,000,000	$	115,000,000
Tranche B		19,800,000		24,300,000
Total debt		134,800,000		139,300,000
Less current maturities included in current liabilities		(5,800,000)		(10,300,000)
Total long-term debt	$	129,000,000	$	129,000,000

We record our debt instruments based on contractual terms. We did not elect to apply the fair value option for recording financial assets and financial liabilities. We measure the fair value of our debt instruments using discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements (categorized as level 3). We do not have any debt instruments with fair value measurements categorized as level 1 or 2 within the fair value hierarchy. 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 equity capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included in our long-term debt. The fair value of long-term debt at March 31, 2013 and December 31, 2012 was estimated to be approximately $123.0 million and $121.6 million, respectively.

In connection with the PSA to sell the coalbed methane properties in Alabama, on May 1, 2013, the Company and the lenders under its Fifth Amended and Restated Credit Agreement executed the Fifth Amendment to such agreement (Amendment), which became effective as of May 1, 2013 and provides the necessary consents to sell the coalbed methane properties in Alabama. The Amendment requires repayment of a minimum of $52 million of borrowings which will result in the elimination of the non-conforming tranche B portion of total outstanding borrowings. Following the expected use of net proceeds for repayment of indebtedness, GeoMet s borrowing base will be the lesser of $83 million or actual outstanding borrowings at such time. This Fifth Amended does not extend the maturity date nor allows additional borrowing; however, it primarily provides a mechanism to recognize direct transaction costs in arriving at the net proceeds to be applied toward the outstanding debt. Among other things, the Amendment increased the capital expenditure restriction in 2013 from $1.0 million to $1.5 million and increased the amount of cash the Company could retain in calculating its monthly loan reduction to $2.0 million from $1.0 million. The Company paid the banks a fee equal to 25 basis points on the tranche B portion of the loan which totaled $48,250. The Amendment is conditioned upon completion of the asset sale described in Note 2 Sale of Coalbed Methane Properties in Alabama.

Note 12 Income Taxes

We record our income taxes using an asset and liability approach. 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 basis of assets and liabilities using enacted tax rates at the end of the period. The effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

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For tax reporting purposes, we have federal and state net operating losses (NOL s) of approximately $137.8 million and $127.0 million, respectively, at March 31, 2013 that are available to reduce future taxable income. For tax reporting purposes, we had federal and state NOL s of approximately $137.8 million and $127.0 million, respectively, at December 31, 2012 that were available to reduce future taxable income. Our first material NOL carryforward expires in 2022 and the last one expires in 2032.

Additionally, for tax reporting purposes, we have a federal capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 5 Discontinued Operations, of approximately $34.9 million at March 31, 2013 that is available to reduce future taxable capital gains and expiring in 2017.

At March 31, 2013, we have a valuation allowance of $98.8 million recorded against our net deferred tax asset which includes $85.4 million related to our U.S. operations and $13.4 million related to the capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 5 Discontinued Operations.

A reconciliation of the effective tax rate to the statutory rate is as follows:

		Total	
Amount computed using statutory rates	$	(1,954,546)	34.00%
State income taxes net of federal benefit		(208,717)	3.63%
Valuation Allowance		2,156,709	-37.52%
Nondeductible items and other		12,804	-0.22%
Income tax provision	$	6,250	-0.11%

Note 13 Common Stock

At March 31, 2013 and December 31, 2012, there were 40,689,486 and 40,690,077 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, 2013 and December 31, 2012 were 254,260 and 254,260 shares of restricted stock, respectively. The following table details the activity related to our common stock for the three months ended March 31, 2013:

	Date	Shares
Common stock outstanding at January 1, 2013		40,690,077
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	01/07/2013	(121)
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	03/15/2013	(470)
Common stock outstanding at March 31, 2013		40,689,486

Note 14 Series A Convertible Redeemable Preferred Stock

At both March 31, 2013 and December 31, 2012, 5,305,865 shares of preferred stock were issued and outstanding. At March 31, 2013, an additional 2,095,967 shares of our Series A Convertible Redeemable Preferred Stock (Preferred Stock) are reserved exclusively for the payment of paid-in-kind dividends (PIK dividends). We measure the fair value of PIK dividends using a discounted cash flow analysis based on our current borrowing rates (categorized as level 3). For the three months ended March 31, 2013, the change in the balance of our Series A Convertible Redeemable Preferred Stock consisted entirely of accretion of the discount of $493,537.

On March 8, 2013, we declared a quarterly dividend of 165,745 shares of Preferred Stock covering the period January 1, 2013 through March 31, 2013. As those shares were not issued until April 1, 2013, they were not been included in the Preferred Stock balance at March 31, 2013. As such, we recorded a dividend payable in Current liabilities in the Consolidated Balance Sheets (Unaudited) at March 31, 2013 at an estimated fair value of $1,075,685.

Note 15 Share-Based Awards

As of March 31, 2013, 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 authorizes the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares are 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,

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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 which are granted solely 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, 2013, we recorded a compensation expense accrual of $58,724 which was allocated as an addition of $6,752 to lease operating expenses and an addition of $51,972 to general and administrative expense. The future compensation cost of all the outstanding awards is $251,530 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 0.70 years.

Incentive Stock Options

The table below summarizes incentive stock option activity for the three months ended March 31, 2013:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2012	1,412,739	$	1.11			
Forfeited	(22,038)	$	1.37			
Outstanding at March 31, 2013	1,390,701	$	1.11	3.8	$	
Options exercisable at March 31, 2013	948,465	$	0.99	4.1	$	

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three months ended March 31, 2013:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2012	974,765	$	2.33			
Outstanding at March 31, 2013, 2012	974,765	$	2.33	1.1	$	
Options exercisable at March 31, 2013	935,242	$	2.42	1.0	$	

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the three months ended March 31, 2013:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock at December 31, 2012	254,260	$ 1.43
Vested	(22,052)	$ 1.32
Forfeited	(470)	$ 1.32
Non-vested restricted stock at March 31, 2013	231,738	$ 1.44

Restricted Stock Unit Awards

On April 5, 2011, we granted 232,089 restricted stock units to our five executive officers. These restricted stock units vest upon the Company s achievement of certain performance targets, but no earlier than ratably over the three year period following the grant date, at which time one common share will be issued and exchanged for each restricted stock unit held. If the requisite performance targets are not achieved in the seven year period ended April 5, 2018, the restricted stock units will expire. Restricted stock units are included in the calculation of diluted earnings per share utilizing the treasury stock method. On April 30, 2012, 99,108 restricted stock units vested with a vesting date fair value of $0.53 per share. On June 25, 2012, 16,428 restricted stock units were forfeited. There have been no grants of restricted stock units subsequent to the aforementioned grant. Unrecognized compensation cost related the restricted stock units is $116,553 at March 31, 2013.

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Note 16 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 are not possible to reasonably predict, management does not believe that the adverse effect on our financial condition, results of operations or cash flows, if any, will be material.

Environmental and Regulatory

As of March 31, 2013, 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.

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

Statement Regarding Forward-Looking Information

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe, anticipate, estimate, expect, intend, may, will, p forecast, plan, and similar expressions are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. Certain of these risks are summarized in this report and under Item 1A. Risk Factors in our 2012 Annual Report on Form 10-K that we filed with the SEC on March 28, 2013, 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, 2012, which are included in our 2012 Annual Report on Form 10-K.

Overview

GeoMet, Inc. is primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba and Black Warrior Basins in Alabama and the central Appalachian Basin in Virginia and West Virginia. We also own additional coalbed methane and oil and gas development rights, principally in Alabama, Virginia, and West Virginia. As of March 31, 2013, we own a total of approximately 138,000 net acres of coalbed methane and oil and gas development rights.

The natural gas industry is capital intensive. Natural gas markets traditionally have been highly volatile. We have historically made substantial capital expenditures in the exploration, development and acquisition of natural gas reserves. Our capital expenditures have been financed primarily with internally generated cash from operations and proceeds from bank borrowings.

Natural gas prices in 2012 were depressed compared with prices generally prevailing over the last several years. The low natural gas prices had pervasive adverse consequences to our business. The borrowing base deficiency was caused by low natural gas prices. On August 8, 2012, we amended our Credit Agreement to include a conforming tranche equal to the borrowing base, and a non-conforming tranche in the amount of the excess. The amendment requires that we use all of our excess cash flows to reduce outstanding borrowings under the non-conforming tranche, and significantly limits our capital expenditures. The Credit Agreement, as amended, has higher interest rates and increased bank fees and professional fees. The maturity date was amended to April 1, 2014. While the amendment provided time to seek a strategic corporate transaction, we believe these efforts have been impeded because of the borrowing base deficiency. However, we have executed a purchase and sale agreement which we believe will eliminate the borrowing base deficiency. The borrowing base deficiency exhausted our hedging credit capacity; thereby, adversely impacting our ability to hedge future gas sales volumes. Retaining and attracting competent personnel has been challenging and is likely to worsen. The need to reduce costs due to lower natural gas prices and operating margins creates vulnerability in conducting our business.

Additionally, depressed natural gas prices resulted in significant property impairments and full valuation of our net deferred tax asset during 2012. Low natural gas prices and our indebtedness contributed to our common stock being delisted by NASDAQ as we had no remaining equity and the market price of our common stock had diminished.

Management s current business plan is primarily focused on eliminating our borrowing base deficiency, maintaining compliance with our Credit Agreement, as amended, maintaining production levels and keeping costs under control.

During 2011 and the first five months of 2012, prices received for natural gas in the United States continued to decline significantly which we believe, among other things, was due to an over-supply of natural gas, primarily resulting from shale drilling and reduced demand due to a much warmer winter than normal. On April 21, 2012, the Henry Hub spot price closed at $1.825/ MMBtu, its lowest in over ten years. Presented below are the NYMEX Settle Prices for the period January 2011 through May 2013 and the NYMEX Forward Curve Prices (as of May 7, 2013) for natural gas for the period June 2013 through December 2013.

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The chart above demonstrates the rapid gas price decline of late 2011 and early 2012. This rapid decline resulted in severe capital and liquidity constraints, creating a borrowing base deficiency under our Credit Agreement. In May 2013, the NYMEX Settle Price has returned to a level similar to that of January 2011. In order to understand why the Company s Borrowing Base has not returned to prior levels, it is important to examine other factors. The table below compares the NYMEX Natural Gas Forward Price Curves as of January 1, 2011 and May 1, 2013.

The chart above demonstrates the significant difference in the forward price curves for comparable periods as of January 1, 2011 and May 1, 2013. The difference in the forward curves is as much as $1.64/MMBtu. We believe that the diminished forward curve and the delayed response by our bank group to the improving price trend are the primary drivers impeding recovery of our borrowing base to previous levels, resulting in the continued need to follow through with our current business plan described above.

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Recent Developments

On May 3, 2013, the Company entered into a purchase and sale agreement (PSA) to sell its coalbed methane properties in Alabama to Saga Resource Partners LLC, for a purchase price of $63.2 million, subject to customary purchase price adjustments. The effective date of this transaction is April 1, 2013, and it is expected to close on or before June 14, 2013, subject to the exercise of preferential rights and customary closing conditions. GeoMet plans to use the cash proceeds from this asset divestiture, net of purchase price adjustments and other transaction related expenditures, to repay borrowings under its Credit Agreement. We have estimated no material income tax impact on the gain resulting from the sale due to offsetting operating losses.

In connection with the PSA to sell the coalbed methane properties in Alabama, on May 1, 2013, the Company and the lenders under its Fifth Amended and Restated Credit Agreement executed the Fifth Amendment to such agreement (Amendment), which became effective as of May 1, 2013 and provides the necessary consents to sell the coalbed methane properties in Alabama. The Amendment requires repayment of a minimum of $52 million of borrowings which will result in the elimination of the non-conforming tranche B portion of total outstanding borrowings. Following the expected use of net proceeds for repayment of indebtedness, GeoMet s borrowing base will be the lesser of $83 million or actual outstanding borrowings at such time.

GeoMet s average net interest in the coalbed methane properties in Alabama being sold produced approximately 9,700 Mcf of natural gas per day during the month of March 2013, or approximately 29% of GeoMet s total production for this time period. As of March 31, 2013 and based on Securities and Exchange Commission guidelines, GeoMet s net proved reserves attributable to the coalbed methane properties in Alabama being sold were estimated to be approximately 43 Bcf, all classified as proved developed reserves.

Lantana Oil & Gas Partners was divestment advisor to GeoMet for the sales process.

Areas of Operation

Our core areas of operations are in the Central Appalachian Basin of Virginia and West Virginia and the Black Warrior and Cahaba Basins in Alabama. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. The Black Warrior and Cahaba Basins are hilly, gently rolling regions and coal mining is also present but less active.

Central Appalachia

Pond Creek and Lasher Fields We are the operator of 298 producing vertical CBM wells in which we own a 99.0% average working interest in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia. Net daily sales of gas averaged 16.1 MMcf per day for the three months ended March 31, 2013. Our natural gas production from the Pond Creek field is delivered into the Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC (ETNG). We have two long-term transportation agreements with ETNG which went into effect in April 2007 with total maximum daily quantities of 15,000 MMBtu s and 10,000 MMBtu s and primary terms of 15 years and 10 years, respectively. Our gas from the Lasher field is delivered into the Columbia Gas Transmission pipeline with firm transportation for 500 MMBtu s per day. We also own and operate a 12 mile, 8 inch high-pressure steel pipeline and gas treatment and compression facilities through which the Pond Creek field natural gas production is gathered, dehydrated, and compressed for delivery into the Jewell Ridge Lateral of the East Tennessee pipeline system.

Pinnate Horizontal Wells We are the operator of 44 producing pinnate horizontal CBM wells in which we own a 71.6% average working interest in central and northern West Virginia. We also have a 33.7% average working interest in 67 non-operated pinnate horizontal wells in central West Virginia. Net daily sales of natural gas averaged 8.4 MMcf per day for the three months ended March 31, 2013. We are party to two firm transportation agreements with total maximum daily capacity of 18,500 MMBtu per day and primary terms expiring from April 2013 through November 2024 which can be automatically extended at GeoMet s option at the maximum tariff rate. We are also party to a 10,000 MMBtu per day gathering contract that is currently in a month-to-month evergreen term. In some cases, our natural gas sales volumes are delivered to market under transportation agreements controlled by our working interest partners. Generally, our natural gas sales volumes are sold at a delivery point into the respective interstate pipeline system utilized.

Alabama

Gurnee Field We are the operator of 217 producing vertical CBM wells, of which we own a 100.0% working interest, in the Gurnee field located in the Cahaba Basin in central Alabama. Net daily sales of gas averaged 4.4 MMcf for the three months ended March 31, 2013. Our natural gas sales volumes from the Cahaba Basin are delivered and sold into the Southern Natural Gas pipeline system and no firm transportation arrangements are necessary. We own and operate a water gathering system which includes an approximately 39 mile pipeline to the Black Warrior River for disposal of produced water under a permit issued by the Alabama Department of Environmental Management. We also own and operate an approximately 17 mile, 12 inch high-pressure steel pipeline and gas treatment and compression facilities through which we gather, dehydrate, and compress natural gas for delivery into the Southern Natural Gas pipeline system.

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Black Warrior Basin We own working, overriding royalty or royalty interests in 1,056 non-operated producing vertical CBM wells in the Black Warrior Basin in central Alabama. All of these non-operated vertical wells have an average royalty and or overriding royalty interest of 12.0%. We also own an average working interest of 15.4% in 498 of these wells. Net daily sales of gas averaged 5.6 MMcf for the three months ended March 31, 2013. Our gas sales volumes from the Black Warrior Basin are delivered and sold into the Southern Natural Gas pipeline system under transportation arrangements controlled by the operators of the properties.

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, 2013.

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Natural Gas Production Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the three months ended March 31, 2013 and 2012. This table should be read with the discussion of the results of operations for the periods presented below.

	Three Months Ended March 31,			
	2013		2012	
Gas sales	$	10,879	$	10,143
Lease operating expenses	$	4,469	$	4,461
Compression and transportation expenses		1,839		2,241
Production taxes		550		470
Total production expenses	$	6,858	$	7,172
Net sales volumes (Consolidated) (MMcf)		3,108		3,629
Pond Creek and Lasher fields		1,452		1,507
Pinnate wells (Central Appalachian Basin)		753		1,008
Gurnee field (Cahaba Basin)		396		457
Black Warrior Basin fields		507		657
Per Mcf data ($/Mcf):				
Average natural gas sales price (Consolidated)	$	3.50	$	2.79
Pond Creek and Lasher fields	$	3.60	$	2.94
Pinnate wells (Central Appalachian Basin)	$	3.40	$	2.60
Gurnee field (Cahaba Basin)	$	3.44	$	2.77
Black Warrior Basin fields	$	3.43	$	2.76
Average natural gas sales price realized (Consolidated)(1)	$	4.50	$	4.12
Lease operating expenses (Consolidated)	$	1.44	$	1.23
Pond Creek and Lasher fields	$	1.21	$	1.05
Pinnate wells (Central Appalachian Basin)	$	1.68	$	1.42
Gurnee field (Cahaba Basin)	$	2.77	$	2.46
Black Warrior Basin fields	$	0.67	$	0.45
Compression and transportation expenses (Consolidated)	$	0.59	$	0.62
Pond Creek and Lasher fields	$	0.58	$	0.53
Pinnate wells (Central Appalachian Basin)	$	1.04	$	1.18
Gurnee field (Cahaba Basin)	$	0.31	$	0.28
Black Warrior Basin fields	$	0.19	$	0.18
Production taxes (Consolidated)	$	0.18	$	0.13
Pond Creek and Lasher fields	$	0.19	$	0.16
Pinnate wells (Central Appalachian Basin)	$	0.15	$	0.06
Gurnee field (Cahaba Basin)	$	0.15	$	0.12
Black Warrior Basin fields	$	0.20	$	0.16
Total production expenses (Consolidated)	$	2.21	$	1.98
Pond Creek and Lasher fields	$	1.98	$	1.74
Pinnate wells (Central Appalachian Basin)	$	2.87	$	2.66
Gurnee field (Cahaba Basin)	$	3.23	$	2.86
Black Warrior Basin fields	$	1.06	$	0.79
Depletion (Consolidated)	$	0.47	$	0.97

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

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Results of Operations

Three months ended March 31, 2013 compared with three months ended March 31, 2012

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

	Three Months Ended March 31,				
		2013		2012	Change
			(in thousands)		
Gas sales volume (MMcf)		3,108		3,629	-14%
Gas sales	$	10,879	$	10,143	7%
Lease operating expenses	$	4,469	$	4,441	1%
Compression expense	$	1,116	$	1,197	-7%
Transportation expense	$	723	$	1,043	-31%
Production taxes	$	551	$	470	17%
Depreciation, depletion and amortization	$	1,506	$	3,630	-59%
Impairment of gas properties	$		$	15,779	NM
General and administrative	$	998	$	1,302	-23%
Realized gains on derivative contracts	$	3,100	$	4,793	-35%
Unrealized losses (gains) from the change in market value of open derivative contracts	$	8,635	$	(5,224)	NM
Interest expense	$	1,676	$	1,276	31%
Income tax expense	$	6	$	44,024	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $0.7 million, or 7%, to $10.9 million compared to the prior year period. The increase in gas sales was primarily the result a 25% increase in natural gas prices, excluding hedging transactions, partially offset by of 13% lower daily production volumes. Production for the quarter was negatively impacted by high line pressure and compression and mechanical downtime in our Pinnate wells in Central Appalachia, as well as mining activities and cost saving initiatives in our non-operated wells in the Black Warrior Basin.

Lease operating expenses. Lease operating expenses remained flat compared to the prior year period.

Compression expense. Compression expense remained flat compared to the prior year period.

Transportation expense. Transportation expense decreased by $0.3 million, or 31%, to $0.7 million compared to the prior year period. The decrease was primarily due to decreasing firm transportation in our non-operated fields resulting from both contract expiration and conveyance of firm transportation volumes to other producers in the area.

Production taxes. Production taxes remained flat compared to the prior year period. However, we expect future production taxes to increase over time as our West Virginia exemptions diminish.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $2.1 million, or 59%, to $1.5 million compared to the prior year period. This decrease was primarily due to the $95.7 million in impairments recorded to our gas properties in 2012.

General and administrative. General and administrative expense decreased by $0.3 million, or 23%, to $1.0 million compared to the prior year period. The decrease was primarily due to decreased employee expenses.

Realized gains on derivative contracts. Realized gains on derivative contracts decreased by $1.7 million, or 35%, to $3.1 million compared to the prior year period. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlements paid to us from the contract counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized gains from the change in market value of open derivative contracts. Unrealized losses on open derivative contracts were $8.6 million in the current year period as compared to unrealized gains of $5.2 million in the prior year period. Unrealized gains and losses 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.

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Interest expense. Interest expense increased by $0.4 million, or 31%, to $1.7 million compared to the prior year period. The increase was primarily due to average interest on the borrowings increasing to 4.27% per annum in the current year period from 2.90% per annum in the prior year period. The increased rates resulted from the August 2012 amendment to the Credit Agreement.

Income tax expense. The income tax expense in the current year period was different than the amount computed using the statutory rate primarily due to a $2.2 million valuation allowance on our deferred tax asset. A reconciliation of the effective tax rate to the statutory rate is as follows:

		Total	
Amount computed using statutory rates	$	(1,954,546)	34.00%
State income taxes net of federal benefit		(208,717)	3.63%
Valuation Allowance		2,156,709	-37.52%
Nondeductible items and other		12,804	-0.22%
Income tax provision	$	6,250	-0.11%

Liquidity and Capital Resources

Cash Flows and Liquidity

As of March 31, 2013, the Company had a working capital deficit of $8.3 million, a retained deficit of $307.8 million and stockholders deficit of $114.6 million. Natural gas prices in 2012 were depressed compared with prices generally prevailing over the last several years. The depressed natural gas prices resulted in significant property impairments, a full valuation of our net deferred tax asset, and a borrowing base deficiency during 2012. The borrowing base deficiency adversely impacted our working capital by reclassifying Long-Term Debt to short-term for the next twelve months required payments. Our Credit Agreement matures on April 1, 2014, and there can be no assurances that we will be able to refinance or repay the borrowings under our Credit Agreement when it matures. As a result, on April 2, 2013, all amounts outstanding under our Credit Agreement were re-classified as current. In addition, on May 1, 2013, we amended credit agreement in conjunction with executing a purchase and sale agreement to sell our coalbed methane properties in Alabama.

Cash flows provided by operations for the three months ended March 31, 2013 were $4.8 million. Cash flows from operations of $4.8 million for the three months ended March 31, 2013 were sufficient to fund net cash used in financing activities of $4.5 million, consisting almost entirely of repayments of borrowings under our credit agreement, and net cash flows used in investing activities of $0.2 million.

Credit Agreement

Under our Credit Agreement, outstanding borrowings may not exceed a borrowing base determined by the lenders. During 2012, the amounts borrowed under our Credit Agreement exceeded the borrowing base. On August 8, 2012, in connection with the excess of borrowings over the borrowing base, we amended the Credit Agreement. Borrowings under the Credit Agreement at August 8, 2012 totaled $148.6 million. The Credit Agreement, as amended, provided for a tranche A loan in the amount of our borrowing base and a tranche B loan in the amount of the excess. The borrowing base, determined as of December 15, 2012, is currently $115.0 million. The tranche B loan was $21.8 million as of March 1, 2013. The borrowing base will be re-determined as of each June and December with the next determination scheduled to be completed by June 15, 2013. Upon any re-determination of the borrowing base, the re-determined amount of the conforming borrowing base will constitute a new tranche A loan, with any decrease in tranche A causing an automatic corresponding increase in tranche B, subject to certain limitations described below, and any increase in tranche A causing an automatic corresponding decrease in tranche B. At the next and any subsequent borrowing base determination, tranche B may not increase by more than 25% of the amount of the principal payments made on tranche B loans since the prior redetermination of the borrowing base. If a future determination of the borrowing base results in the outstanding amount of the tranche B loan exceeding the amount permitted under the Credit Agreement, we have 30 days to repay such excess. The Credit Agreement no longer provides for loans to be available on a revolving basis up to the amount of the borrowing base. As a result, the current outstanding loans, once repaid, may not be re-borrowed by the Company. All outstanding borrowings under the Credit Agreement are due and payable on April 1, 2014. In addition, the Credit Agreement obligates us to reduce our borrowings monthly by substantially all of our available excess cash flow. The Credit Agreement provides for interest to accrue at a rate calculated, at our option, at the Adjusted Base Rate plus a margin of 2.00% on tranche A loans and 4.00% on tranche B loans or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 3.00% on tranche A loans and 5.00% on tranche B loans. Adjusted Base Rate is

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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%. The Credit Agreement requires an additional payment to the lenders based on the amount of tranche B loans as follows:

Calculation Date	Fee Amount (basis points)	Date Payable
5/25/2013	125 bps	6/1/2013
8/25/2013	150 bps	9/1/2013
11/25/2013	175 bps	12/1/2013

All financial covenants were deleted by the Amendment and were replaced with a capital expenditure covenant (a maximum of $1.5 million in 2012 and $1.0 million in 2013) and a maximum debt covenant as follows:

Quarter Ending		Maximum Principal Outstanding
3/31/2013	$	136,000,000
6/30/2013	$	132,700,000
9/30/2013	$	131,500,000
12/31/2013	$	129,000,000

In connection with the PSA to sell the coalbed methane properties in Alabama, on May 1, 2013, the Company and the lenders under its Fifth Amended and Restated Credit Agreement executed the Fifth Amendment to such agreement (Amendment), which became effective as of May 1, 2013 and provides the necessary consents to sell the coalbed methane properties in Alabama. The Amendment requires repayment of a minimum of $52 million of borrowings which will result in the elimination of the non-conforming tranche B portion of total outstanding borrowings. Following the expected use of net proceeds for repayment of indebtedness, GeoMet s borrowing base will be the lesser of $83 million or actual outstanding borrowings at such time. This Fifth Amended does not extend the maturity date nor allows additional borrowing; however, it primarily provides a mechanism to recognize direct transaction costs in arriving at the net proceeds to be applied toward the outstanding debt. Among other things, the Amendment increased the capital expenditure restriction in 2013 from $1.0 million to $1.5 million and increased the amount of cash the Company could retain in calculating its monthly loan reduction to $2.0 million from $1.0 million. The Company paid the banks a fee equal to 25 basis points on the tranche B portion of the loan which totaled $48,250. The Amendment is conditioned upon completion of the asset sale described in Note 2 Sale of Coalbed Methane Properties in Alabama in the Notes to Consolidated Financial Statements (Unaudited).

Natural Gas Price Risk and Related 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 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. Our Credit Agreement limits amounts of future natural gas production that we may hedge. At December 31, 2012, we do not have the ability to enter into additional natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

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 (Unaudited) and Consolidated Statements of Operations (Unaudited).

Commodity Price Risk and Related Hedging Activities

At March 31, 2013, we had the following natural gas collar positions:

Period	Volume (MMBtu)		Sold Ceiling		Bought Floor		Fair Value
January 2014 through December 2015	3,650,000	$	4.30	$	3.60	$	(904,032)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50		(1,141,532)
	7,300,000					$	(2,045,564)

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At March 31, 2013, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
April 2013 through March 2014	2,920,000	$	3.81		(1,044,483)
April 2013 through March 2014	2,920,000	$	3.82		(1,016,450)
April 2013 through December 2013	1,650,000	$	3.60		(832,643)
April 2013 through December 2013	2,750,000	$	3.25		(2,321,884)
	10,240,000			$	(5,215,460)

We have hedged approximately 92% of our remaining forecasted production for 2013 at a fixed price of $3.60 per Mcf. As a result, we expect changes in natural gas prices to have a minimal impact on our cash flows through the end of 2013.

Capital Expenditures

The following table is a summary of our capital expenditures on an accrual basis by category for the three months ended March 31, 2013 and 2012:

		2013		2012
Capital expenditures:				
Leasehold acquisition	$	94,266	$	148,619
Exploration				
Development		(21,988)		(63,206)
Capitalized overhead				72,949
Other items		6,037		58,076
Total capital expenditures	$	78,315	$	216,438

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 2012 Annual Report on Form 10-K that we filed with the SEC on March 28, 2013.

Recent Pronouncements

In February 2013, the Financial Accounting Standards Board (FASB), issued Accounting Standards Update (ASU), No. 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the

Reporting Date. ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations addressed within existing guidance. The update is effective for interim and annual periods beginning after December 15, 2013 and is required to be applied retrospectively to all prior periods presented for those obligations that existed upon adoption of ASU 2013-04. We are presently assessing the potential impact of ASU 2013-04.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. The update requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under accounting principles generally accepted in the United States (GAAP) to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. The amendments are effective prospectively for reporting periods beginning after December 15, 2012 The Company has adopted and applied the provisions of ASU 2012-02 which did not impact its operating results, financial position or cash flows.

In January 2013, the FASB issued ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in this update clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company has adopted and applied the provisions of ASU 2013-01. As the Company currently presents unrealized gains (losses) on commodity derivatives on a gross basis on our Consolidated Balance Sheets (Unaudited), no material impact was noted.

In July 2012, the FASB issued ASU 2012-02, which amends the guidance in ASC 350-30 on testing indefinite-lived intangible assets, other than goodwill, for impairment. The FASB issued the ASU in response to feedback on ASU 2011-08, which amended the goodwill impairment testing requirements by allowing an entity to perform a qualitative impairment assessment before proceeding to the two- step impairment test. Similarly, under ASU 2012-02, an entity testing an indefinite-lived intangible asset for impairment has the option of performing a qualitative assessment before calculating the fair value of the asset. Although ASU 2012-02 revises the examples of events and circumstances that an entity should consider in interim periods, it does not revise the requirements to test indefinite-lived intangible assets (1) annually for impairment and (2) between annual tests if there is a change in events or

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circumstances. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. The Company has adopted and applied the provisions of ASU 2012-02 which did not impact its operating results, financial position or cash flows.

Environmental Regulations

Our exploration and production operations are subject to significant federal, state, and local environmental laws and regulations governing environmental protection as well as the discharge of substances into the environment. These laws and regulations may restrict the types, quantities, and concentrations of various substances that can be released into the environment as a result of natural gas drilling, production, and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas or that impact protected species; require permits or other governmental authorization before commencing certain activities and require the installation of pollution control measures as a condition of such permits or authorizations; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations are subject to injunctive relief, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future could have a material adverse impact on our operations.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws or regulations or the modification of existing laws or regulations could have a material adverse effect on our operations. As a general matter, the recent trend in environmental legislation and regulation is toward stricter standards, and this trend will likely continue. To date, we have not been required to expend extraordinary resources in order to satisfy existing applicable environmental laws and regulations. However, costs to comply with existing and any new environmental laws and regulations could become material. Moreover, a serious incident of pollution may result in the suspension or cessation of operations in the affected area or in substantial liabilities to third parties. Although we maintain insurance coverage against costs of clean-up operations, no assurance can be given that we are fully insured against all such potential risks. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

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, 2013, a 10% decrease in the prices received for natural gas production would have decreased our gas revenues by approximately $1.09 million, which would have been offset by approximately $0.43 million by increased 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, 2013, we had $134.8 million outstanding under our Credit Agreement. For the three months ended March 31, 2013 and 2012, interest on the borrowings averaged 4.27% and 2.90% per annum, respectively. 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 weighted average balance outstanding under our Credit Agreement, 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, 2013 by approximately $0.34 million.

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, 2013 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

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

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Environmental and Regulatory

As of March 31, 2013, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 1A. Risk Factors

There has been the following addition to the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2012:

Our ability to close the sale of our Alabama properties depends upon events beyond our control, which if they were to occur would cause us to be unable to consummate the sale.

The purchase and sale agreement contains customary provisions which require an adjustment to the purchase price for net cash flows for the period April 1, 2013 through the closing date related to the purchased properties and provide the buyer the right to review title to our properties and environmental matters, and to exclude properties or reduce the purchase price for properties if defects are discovered in title or environmental matters and, if title defects or environmental matters exceed a threshold in the purchase and sale agreement, either we or the buyer may terminate the purchase and sale agreement. In addition, if the holder of a preferential right to purchase one of the Alabama properties exercises that right, the buyer is entitled to terminate the purchase and sale agreement. It is therefore possible that we may not be able to consummate the sale of the Alabama properties, or that the purchase price could be reduced for title or environmental matters.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

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

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SIGNATURES

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

GeoMet, Inc.

Date: May 15, 2013	By	/S/ TONY OVIEDO **Tony Oviedo, Senior Vice President, Chief Financial Officer,** **Chief Accounting Officer and Controller (Principal Financial Officer)**

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INDEX TO EXHIBITS

Exhibit Number	Exhibits
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).
101**	Interactive Data Files.

* Attached hereto.

** Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability.