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

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**FORM 10-Q**

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

For the quarterly period ended June 30, 2008

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number 000-52155

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**GeoMet, Inc.**

(Exact name of registrant as specified in its charter)

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**Delaware**  
(State or other jurisdiction of  
incorporation or organization)

**76-0662382**  
(I.R.S. Employer  
Identification Number)

**909 Fannin, Suite 1850  
Houston, Texas 77010  
(713) 659-3855**

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

N/A

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

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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.  Yes  No

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

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

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

As of July 1, 2008 there were 39,274,331 shares issued and outstanding of GeoMet, Inc.'s common stock, par value \$0.001 per share.

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**Item 1. Financial Statements**

**GEOMET, INC. AND SUBSIDIARIES**  
**Consolidated Balance Sheets**

	<b>(Unaudited)</b>	
	<b>June 30,</b>	<b>December 31,</b>
	<b>2008</b>	<b>2007</b>
<b>ASSETS</b>		
Current Assets:		
Cash and cash equivalents .....	\$ 4,036,343	\$ 1,540,516
Accounts receivable .....	7,654,532	4,881,397
Inventory .....	2,411,346	2,355,595
Derivative asset .....	67,714	2,247,248
Deferred income taxes .....	5,245,100	—
Other current assets .....	262,127	484,341
Total current assets .....	19,677,162	11,509,097
Gas properties—utilizing the full cost method of accounting:		
Proved gas properties .....	385,497,306	370,404,336
Unevaluated gas properties, not subject to amortization .....	30,436,462	25,174,764
Other property and equipment .....	2,850,099	2,536,619
Total property and equipment .....	418,783,867	398,115,719
Less accumulated depreciation, depletion, and amortization .....	(36,768,850)	(31,886,633)
Property and equipment—net .....	382,015,017	366,229,086
Other noncurrent assets:		
Derivative asset .....	189,474	90,427
Other .....	737,553	848,816
Total other noncurrent assets .....	927,027	939,243
<b>TOTAL ASSETS</b> .....	<b>\$ 402,619,206</b>	<b>\$ 378,677,426</b>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current Liabilities:		
Accounts payable .....	\$ 12,430,828	\$ 7,536,274
Accrued liabilities .....	3,309,098	5,087,871
Deferred income taxes .....	—	770,675
Derivative liability .....	13,790,470	—
Asset retirement liability .....	72,956	74,387
Current portion of long-term debt .....	108,699	102,586
Total current liabilities .....	29,712,051	13,571,793
Long-term debt .....	100,153,732	96,729,722
Derivative liability .....	4,881,228	—
Asset retirement liability .....	4,072,197	2,915,855
Other long-term accrued liabilities .....	122,181	138,471
Deferred income taxes .....	50,144,913	46,645,879
<b>TOTAL LIABILITIES</b> .....	<b>189,086,302</b>	<b>160,001,720</b>
Commitments and contingencies (Note 10)		
Stockholders' Equity:		
Preferred stock, \$0.001 par value—authorized 10,000,000, none issued		
Common stock, \$0.001 par value—authorized 125,000,000 shares; issued and outstanding 39,274,331 and 38,962,359 at June 30, 2008 and December 31, 2007, respectively .....	39,274	38,962
Paid-in capital .....	188,225,077	187,550,484
Accumulated other comprehensive income .....	1,900,445	2,394,001
Retained earnings .....	23,590,797	28,909,363

	(Unaudited) June 30, 2008	December 31, 2007
Less notes receivable.....	(222,689)	(217,104)
TOTAL STOCKHOLDERS' EQUITY .....	213,532,904	218,675,706
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY .....	\$ 402,619,206	\$ 378,677,426

See accompanying Notes to Consolidated Financial Statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
<b>Revenues:</b>				
Gas sales .....	\$ 20,700,928	\$ 13,438,859	\$ 36,282,106	\$ 25,287,061
Operating fees and other .....	203,528	324,247	501,157	616,000
Total revenues .....	20,904,456	13,763,106	36,783,263	25,903,061
<b>Expenses:</b>				
Lease operating expense .....	3,640,244	3,424,409	7,391,570	6,793,644
Compression and transportation expense .....	1,005,386	1,355,148	2,048,195	2,867,566
Production taxes .....	634,109	317,368	1,056,045	597,681
Depreciation, depletion and amortization .....	2,489,266	2,265,451	4,948,595	4,340,774
General and administrative .....	2,887,237	2,227,424	5,379,707	4,503,688
Realized losses (gains) on derivative contracts .....	1,493,064	(50,404)	631,236	(1,296,530)
Unrealized losses (gains) on derivative contracts .....	12,097,929	(1,860,987)	20,744,592	2,713,229
Total operating expenses .....	24,247,235	7,678,409	42,199,940	20,520,052
Operating (loss) income from continuing operations .....	(3,342,779)	6,084,697	(5,416,677)	5,383,009
<b>Other income (expense):</b>				
Interest income .....	13,286	18,124	20,063	25,097
Interest expense (net of amounts capitalized) .....	(1,117,276)	(1,260,412)	(2,420,469)	(2,135,417)
Other .....	34,892	4,045	29,343	(24,623)
Total other expense .....	(1,069,098)	(1,238,243)	(2,371,063)	(2,134,943)
(Loss) income before income taxes and discontinued operations .....	(4,411,877)	4,846,454	(7,787,740)	3,248,066
Income tax (benefit) expense .....	(1,235,253)	1,892,765	(2,469,173)	1,396,181
(Loss) income from continuing operations .....	(3,176,624)	2,953,689	(5,318,567)	1,851,885
Discontinued operations, net of tax .....	—	44,952	—	120,893
Net (loss) income .....	\$ (3,176,624)	\$ 2,998,641	\$ (5,318,567)	\$ 1,972,778
<b>(Loss) earnings per share:</b>				
<b>(Loss) income from continuing operations</b>				
Basic .....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
Diluted .....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
<b>Discontinued operations</b>				
Basic .....	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00
Diluted .....	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00
<b>Net (loss) income</b>				
Basic .....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
Diluted .....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
<b>Weighted average number of common shares:</b>				
Basic .....	39,271,342	38,710,319	39,139,812	38,704,051
Diluted .....	39,271,342	39,400,890	39,139,812	39,385,935

See accompanying Notes to Consolidated Financial Statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Net (loss) income.....	\$ (3,176,624)	\$ 2,998,641	\$ (5,318,567)	\$ 1,972,778
Gain (loss) on foreign currency translation adjustment, net of tax.....	139,335	1,460,022	(331,884)	1,366,060
Gain (loss) on interest rate swap, net of tax.....	541,975	—	(5,186)	—
Other comprehensive (loss) income .....	<u>\$ (2,495,313)</u>	<u>\$ 4,458,663</u>	<u>\$ (5,655,637)</u>	<u>\$ 3,338,838</u>

See accompanying Notes to Consolidated Financial Statements.

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

	Six Months Ended June 30,	
	2008	2007
Cash flows provided by operating activities:		
Net (loss) income .....	\$ (5,318,567)	\$ 1,972,778
Adjustments to reconcile net income to net cash flows provided by operating activities: .....		
Depreciation, depletion and amortization .....	4,948,595	4,427,660
Amortization of debt issuance costs .....	85,981	69,922
Deferred income tax (benefit) expense .....	(2,469,173)	1,491,029
Unrealized losses from the change in market value of open derivative contracts .....	20,744,592	2,713,229
Stock-based compensation.....	383,606	163,024
Gain (loss) on sale of assets.....	20,512	(15,954)
Accretion expense.....	167,944	103,036
Changes in operating assets and liabilities:.....		
Accounts receivable .....	(2,778,368)	2,379,534
Other current assets .....	166,546	456,473
Accounts payable .....	1,495,674	(3,503,299)
Other accrued liabilities .....	127,022	561,546
Net cash provided by operating activities .....	17,574,364	10,818,978
Cash flows used in investing activities:		
Capital expenditures .....	(18,600,519)	(29,951,279)
Proceeds from sale of other property and equipment .....	26,000	22,159
Other assets .....	25,071	(66,568)
Net cash used in investing activities .....	(18,549,448)	(29,995,688)
Cash flows provided by financing activities:		
Treasury stock .....	(23,359)	(4,382)
Proceeds from exercise of stock options .....	75,025	140,696
Credit facility borrowings .....	3,500,000	20,500,000
Payments on other debt .....	(69,877)	(64,264)
Net cash provided by financing activities .....	3,481,789	20,572,050
Effect of exchange rate changes on cash .....	(10,878)	27,905
Increase in cash and cash equivalents .....	2,495,827	1,423,245
Cash and cash equivalents at beginning of period .....	1,540,516	1,414,476
Cash and cash equivalents at end of period .....	\$ 4,036,343	\$ 2,837,721

See accompanying Notes to Consolidated Financial Statements.

**GEOMET, INC. AND SUBSIDIARIES**  
**Notes to Consolidated Financial Statements**  
**(Unaudited)**

**Note 1 — Organization and Our Business**

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

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America. Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements for the fiscal year ended December 31, 2007 and the accompanying notes included in our Annual Report on Form 10-K, which we filed with the Securities and Exchange Commission (the “SEC”) on March 14, 2008.

**Note 2 — Recent Accounting Pronouncements**

In September 2006, the Financial Accounting Standards Board (the “FASB”) issued Statement of Financial Accounting Standard No. 157, “Fair Value Measurements” (“SFAS 157”). SFAS 157 is effective for fiscal years beginning after November 15, 2007. Effective January 1, 2008, we adopted SFAS 157, which provides a framework for measuring fair value under accounting principles generally accepted in the United States. SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are derived from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of SFAS 157 in Note 6 — Derivative Instruments and Hedging Activities. The FASB has also issued Staff Position FAS 157-2 (FSP No. 157-2), which delays the effective date of SFAS 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. Effective January 1, 2008, the Company adopted SFAS 157 as discussed above and has elected to defer the application thereof to nonfinancial assets and liabilities in accordance with FSP No. 157-2. Non-recurring nonfinancial assets and nonfinancial liabilities for which the Company has not applied the provisions of SFAS 157 include those measured at fair value in goodwill impairment testing, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination.

On February 15, 2007, the FASB issued SFAS Statement No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB 115” (“SFAS 159”). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of SFAS 159 are elective; however, the amendment to FASB 115, “Accounting for Certain Investments in Debt and Equity Securities,” applies to all entities that own trading and available-for-sale securities. The fair value option created by SFAS 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. SFAS 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Effective January 1, 2008, we adopted SFAS 159. We did not elect the fair value option for any of our assets or liabilities that did not already require such treatment under other authoritative literature.

In March 2008, the FASB issued SFAS Statement No. 161, “Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133” (“SFAS 161”). This standard changes the disclosure requirements

for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact of SFAS 161 on our disclosures relating to derivative instruments and hedging activities. The statement only provides for enhanced disclosure. Therefore, adoption will have no impact on our financial position or results of operations.

### Note 3 — Earnings Per Share

**(Loss) Earnings Per Share of Common Stock**—Basic (loss) earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted (loss) earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive (loss) earnings per share consider the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of the numerator and denominator is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
<b>(Loss) income from continuing operations per share:</b>				
Basic-net (loss) income per share.....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
Diluted-net (loss) income per share.....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
<b>Discontinued operations per share:</b>				
Basic-net income per share.....	\$ —	\$ —	\$ —	\$ —
Diluted-net income per share.....	\$ —	\$ —	\$ —	\$ —
<b>Net (loss) income per share:</b>				
Basic-net (loss) income per share.....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
Diluted-net (loss) income per share.....	\$ (0.08)	\$ 0.08	\$ (0.14)	\$ 0.05
<b>Numerator</b>				
(Loss) income from continuing operations.....	\$ (3,176,624)	\$ 2,953,689	\$ (5,318,567)	\$ 1,851,885
Discontinued operations.....	—	44,952	—	120,893
Net (loss) income available to common stockholders ....	\$ (3,176,624)	\$ 2,998,641	\$ (5,318,567)	\$ 1,972,778
<b>Denominator:</b>				
Weighted average shares outstanding-basic.....	39,271,342	38,710,319	39,139,812	38,704,051
Add potentially dilutive securities:				
Stock options .....	—	690,571	—	681,884
Weighted average shares and potential dilutive shares outstanding.....	39,271,342	39,400,890	39,139,812	39,385,935

Diluted net income per share for the three and six months ended June 30, 2008 excluded the effect of 1,916,871 potentially dilutive shares because we reported a net loss. Diluted net income per share for the three and six months ended June 30, 2007 excluded the effect of outstanding options to purchase 394,302 and 237,090 shares, respectively, because the average market price for the period was less than the exercise price.

### Note 4 — Gas Properties

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

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

Estimation of proved gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. 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 future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the “ceiling limitation”). We perform a quarterly ceiling limitation test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling limitation test is imposed separately for our U.S. and Canadian cost centers. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders’ equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

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

#### *Property Conveyance and Dispute*

We had previously entered into an agreement to sell our interests in a property, subject to a preferential right to purchase held by another party, which the other party subsequently exercised. A dispute arose as to whether the preferential right to purchase applied to the interests we own in this property. We asserted that the preferential right to purchase did not apply, and that we were entitled to retain all remaining interests we own in the property. We believe we have reached an agreement to assign ownership of the property. The unresolved issue in this dispute relates to the correct application of interest to the sums owed between the parties. As of June 30, 2008, we have estimated the settlement amount to be approximately \$220 thousand and have accrued a liability in that amount as a purchase price adjustment. Although we cannot predict the ultimate outcome at this time, we believe that the actual settlement will not be materially different than the amount we have accrued at June 30, 2008. The proved reserves being conveyed represent less than 1% of our total proved reserves and the related production is approximately 900 Mcf per day.

#### **Note 5 — Asset Retirement Liability**

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

The following table details the changes to our asset retirement liability for the six months ended June 30, 2008:

Current portion of liability at January 1, 2008 .....	\$	74,387
Add: Long-term asset retirement liability at January 1, 2008 .....		2,915,855
Asset retirement liability at January 1, 2008 .....		2,990,242
Liabilities incurred .....		135,502
Liabilities settled .....		(96,753)
Accretion .....		187,597
Revisions in estimates .....		934,924
Foreign currency translation.....		(6,359)
Asset retirement liability at June 30, 2008 .....		4,145,153
Less: Current portion of liability .....		(72,956)
Long-term asset retirement liability .....	\$	<u>4,072,197</u>

Revisions in estimates of our asset retirement liability totaling \$934,924 were due to specific lease agreement requirements related to plugging and abandonment of certain wells and were capitalized in the full cost pool of our gas properties.

**Note 6 — Derivative Instruments and Hedging Activities**

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

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

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

During the three and six months ended June 30, 2008, we had the following losses (gains) on our hedging instruments:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Realized losses (gains) on derivative contracts.....	\$ 1,493,064	\$ (50,404)	\$ 631,236	\$ (1,296,530)
Unrealized losses (gains) on derivative contracts.....	12,097,929	(1,860,987)	20,744,592	2,713,229
Total losses (gains).....	\$ 13,590,993	\$ (1,911,391)	\$ 21,375,828	\$ 1,416,699

**Commodity Price Risk and Related Hedging Activities.**

At June 30, 2008, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor
July through October 2008 .....	984,000	\$ 10.50	\$ 7.00	\$ 5.00
November 2008 through March 2009.....	906,000	\$ 11.00	\$ 8.50	\$ 6.25
November 2008 through March 2009.....	906,000	\$ 11.00	\$ 8.84	\$ 6.00
April through October 2009.....	1,284,000	\$ 10.00	\$ 7.50	\$ 5.25
April through October 2009.....	1,284,000	\$ 10.00	\$ 8.50	\$ 6.50
November 2009 through March 2010.....	906,000	\$ 11.20	\$ 9.50	\$ 7.00

At June 30, 2008, the Company had the following natural gas swap position:

Period	Volume (MMBtu)	Price
July through October 2008 .....	492,000	\$ 8.00

### ***Interest Rate Risks and Related Hedging Activities***

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS No. 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At June 30, 2008, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate	Notional amount
Floating-to-fixed swap.....	12/14/2007	12/14/2010	3.863%(1)	\$ 15,000,000
Floating-to-fixed swap.....	1/3/2008	1/4/2010	3.950%(1)	\$ 10,000,000
Floating-to-fixed swap.....	3/25/2008	3/25/2010	2.380%(1)	\$ 10,000,000
Floating-to-fixed swap.....	5/13/2008	5/13/2010	3.069%(1)	\$ 5,000,000

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

For the three and six months ended June 30, 2008, we recognized no ineffective portion of our cash flow hedges.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. SFAS 157 clarifies that a fair value measurement for a 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 liabilities stated below. The following is a description of the individual valuation methodologies used for our derivative instruments measured at fair value:

- *Natural Gas Hedges* – In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our credit standing are used to discount future cash flows.
- *Interest Rate Swaps* – In order to estimate the fair value of our interest rate swaps, we use a yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available Money Market rates and Interest Rate swap market data. To extrapolate future cash flows, discount factors incorporating our credit standing are used to discount future cash flows.

Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our derivative instruments at June 30, 2008 and December 31, 2007 were as follows:

	June 30, 2008	December 31, 2007
Interest rate swap - asset .....	\$ 257,188	\$ 10,884
Natural gas hedge - asset .....	—	2,326,791
Total derivative assets .....	<u>\$ 257,188</u>	<u>\$ 2,337,675</u>
Interest rate swap - liability .....	\$ 253,897	\$ —
Natural gas hedge liability .....	18,417,801	—
Total derivative liabilities.....	<u>\$ 18,671,698</u>	<u>\$ —</u>

#### Note 7 — Long-Term Debt

We have a revolving credit facility with a current borrowing base of \$180 million, maturing January 6, 2011. Our revolving credit facility permits us to borrow and repay amounts as needed based on the available borrowing base as determined in the credit agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the revolving credit facility is based upon the reserve valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of June 30, 2008, we had \$99.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of \$80.5 million under our \$180 million borrowing base. For the three and six months ended June 30, 2008 we borrowed \$31 million and \$50.5 million, respectively, and made payments of \$32 million and \$47 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at either the bank's adjusted base rate, which is the bank's base rate of at least the Federal Funds Rate plus 0.5%, or the adjusted LIBOR rate, plus a margin of 1.00% to 2.00%, based on borrowing base usage. The rates at June 30, 2008 and December 31, 2007 were 3.90% and 6.29%, respectively.

The following is a summary of our long-term debt at June 30, 2008 and December 31, 2007:

	June 30, 2008	December 31, 2007
Borrowings under revolving credit facility .....	\$ 99,500,000	\$ 96,000,000
Note payable to a third party, annual installments of \$53,000 through January 2011, interest-bearing at 8.25% annually, unsecured.....	135,972	174,570
Note payable to an individual, semi-monthly installments of \$644, through September 2015, interest-bearing at 12.6% annually, unsecured.....	124,153	129,240
Salary continuation payable to an individual, semi-monthly installments of \$3,958, through December 2015, non-interest-bearing (less amortization discount of \$572,074, with an effective rate of 8.25%), unsecured.....	502,306	528,498
Total debt .....	<u>100,262,431</u>	<u>96,832,308</u>
Less current maturities included in current liabilities .....	<u>(108,699)</u>	<u>(102,586)</u>
Total long-term debt .....	<u>\$ 100,153,732</u>	<u>\$ 96,729,722</u>

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio of 1.0 to 1.0, and a rate of consolidated EBITDA to interest expense of up to 2.75 to 1.0, both as defined in the credit agreement. Consolidated EBITDA is defined as net income before net interest expense, other non-operating income or losses, income taxes, and depreciation, depletion and amortization. Consolidated EBITDA is not a measure of performance calculated in accordance with accounting principles generally accepted in the United States of America. As of June 30, 2008, we were in compliance with all of the covenants in the credit agreement.

#### Note 8 — Common Stock

At June 30, 2008 and December 31, 2007, there were 39,274,331 shares and 38,962,359 shares, respectively, of common stock outstanding. At June 30, 2008 and December 31, 2007, common stock outstanding included 10,400 shares and 7,828 shares, respectively, of treasury stock held by the Company. For the three and six months ended June 30, 2008, we

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

### Note 9 — Share-Based Awards

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123R, “Share-Based Payment”, using the prospective transition method. For share-based awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we will not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

As of June 30, 2008, we have two stock-based award plans authorized, our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted our 2006 Long-Term Incentive Plan, although we will continue to issue shares of our common stock upon exercise of awards previously granted under the 2005 Stock Option Plan.

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

In March 2008, we granted 164,604 restricted stock awards with time vesting criteria to certain key employees, including our four executive officers. Additionally, we granted 89,202 restricted stock awards with performance vesting criteria to our four executive officers and two other officers. We also granted 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. The restricted stock awards will vest as a result of a triggering event such as a corporate change of control or merger. During the three and six months ended June 30, 2008, no shares and 4,891 shares, respectively, of restricted stock were forfeited. During the three and six months ended June 30, 2008, we recorded a compensation expense accrual of \$339,064 and \$609,284, respectively, of which \$19,117 and \$26,697, respectively, was allocated to lease operating expenses, \$176,183 and \$356,909, respectively, to general and administrative expenses, and \$143,764 and \$225,678, respectively, was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is \$2,161,576 million, 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 2.25 years.

Significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 40%, risk-free interest rate of 3.15%, an expected term of 4.5 years, and forfeiture rates from 5% to 15%.

#### *Incentive Stock Options*

The table below summarizes incentive stock option activity for the six months ended June 30, 2008:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2007.....	682,277	\$ 6.96		
Forfeited.....	(73,295)	\$ 3.30		
Exercised .....	(44,337)	\$ 1.69		
Outstanding at June 30, 2008.....	564,645	\$ 7.84	4.77	\$ 1,246,861
Options exercisable at June 30, 2008.....	284,461	\$ 7.38	3.76	\$ 805,060

The total intrinsic value of incentive stock options exercised during the six months ended June 30, 2008 was \$220,275. The total intrinsic value of the incentive stock options exercised during the six months ended June 30, 2007 was \$193,640. During the six months ended June 30, 2008, no incentive stock options were granted. The weighted average grant-date fair value of incentive stock options granted during the six months ended June 30, 2007 was \$3.17.

#### *Non-Qualified Stock Options*

The table below summarizes non-qualified stock option activity for the six months ended June 30, 2008:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2007 .....	1,311,055	\$ 4.02		
Forfeited.....	(12,889)	\$ 9.63		
Outstanding at June 30, 2008.....	1,298,166	\$ 3.96	4.83	\$ 7,572,978
Options exercisable at June 30, 2008.....	1,114,970	\$ 3.21	4.64	\$ 7,259,200

During the six months ended June 30, 2008 and 2007, no non-qualified stock options were exercised nor granted.

#### *Restricted Stock Awards*

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2008:

	Non-Vested Restricted Stock Awards	Weighted Average Value Per Share At Grant Date
Non-vested restricted stock at December 31, 2007 .....	173,998	\$ 7.21
Granted.....	253,806	6.41
Vested .....	(20,800)	7.96
Forfeited .....	(4,891)	7.21
Non-vested restricted stock at June 30, 2008 .....	402,113	\$ 6.67

On June 15, 2008, 20,800 shares restricted stock vested. The fair value of the shares that vested on that date was \$186,576.

#### **Note 10 — Commitments and Contingencies**

From time to time we may be 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 outcome will have a material adverse effect on our financial condition, results of operations or operating cash flows, except as described below.

#### **CNX Surface Use Disputes**

We constructed a 12-mile gathering line in the Pond Creek field, a portion of which traverses a right-of-way granted to us by Pocahontas Mining Limited Liability Company (“PMC”) in Buchanan County, Virginia. Our Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC (“CNX”), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. No amounts were deposited

into escrow. On November 5, 2007, the Virginia Supreme Court accepted PMC's and our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We presented oral arguments before the Virginia Supreme Court on June 2, 2008 and expect a decision by early September, 2008. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the property. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. No gas from the Pond Creek field has ever been shut in as a result of the CNX surface disputes. We believe it is unlikely we will be prevented from transporting our gas to market through our Pond Creek gathering line if we do not prevail in our CNX surface dispute. However, in such event, we believe we have alternatives available to deliver our gas to market. Such alternatives could require the expenditure of material amounts and it is possible we may be unable to deliver our gas from the Pond Creek field to market for some period of time.

### **CNX Antitrust Action**

We filed a complaint against CNX and Island Creek Coal Company ("Island Creek"), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX's alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX's intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX's position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we have filed an amended petition that restates with specificity our claims against CNX and Island Creek, names Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as additional defendants, and seeks actual damages of \$385.6 million. We are seeking treble damages for the alleged violations of the Virginia Antitrust Act, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

### **Environmental and Regulatory**

As of June 30, 2008, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

### **Note 11 — Discontinued Operations**

As of September 30, 2007, we discontinued the third-party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we exercised our purchase option and acquired 100% of Shamrock Energy LLC, our discontinued gas marketing subsidiary. Over 99% of the net assets acquired were current, approximated their fair value and were equal to zero. Shamrock Energy LLC was a low margin business and as a result it did not have a significant impact on our results of operations. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, "Business Combinations," whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. Goodwill was not recorded because the purchase price approximated the fair value of the net assets acquired.

As a result of exiting the third-party marketing business, we are treating these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations were as follows:

Consolidated Statement of Operation Data:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Gas marketing revenues .....	\$ —	\$ 8,901,311	\$ —	\$ 17,443,797
Purchased gas .....	—	(8,795,737)	—	(17,228,056)
Income before tax .....	—	105,574	—	215,741
Income tax expense .....	—	(60,622)	—	(94,848)
Discontinued operations .....	\$ —	\$ 44,952	\$ —	\$ 120,893

Balance Sheet Data:

	June 30, 2008	December 31, 2007
Current Assets:		
Cash and cash equivalents .....	\$ —	\$ 175,398
Accounts receivable .....	—	15,530
Other .....	—	14,945
Total assets .....	\$ —	205,873
Current Liabilities:		
Accounts payable .....	\$ —	\$ 86,510
Stockholder's equity .....	—	119,363
Total liabilities and stockholder's equity .....	\$ —	\$ 205,873

**Note 12 — Income Taxes**

Our effective tax rate differs from the federal statutory rate primarily due to net operating losses in Canada and Louisiana from which we are currently unable to benefit. The Canadian and Louisiana net operating losses are fully reserved because it is more likely than not that we will not use those NOL's to offset current tax liabilities in future years. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to June 30, 2009. For tax reporting purposes, we have federal and state NOL's of approximately \$80.5 million and \$6.0 million, respectively, at June 30, 2008 that are available to reduce future taxable income. If not utilized, the federal carryforwards would begin to expire in 2022. Certain immaterial portions of the state NOL's will expire prior to 2022.

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

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

You should read "Management's Discussion and Analysis of Financial Condition and Results of Operations" in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2007, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 14, 2008.

## Overview

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (“coalbed methane” or “CBM”) and non-conventional shallow gas. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of June 30, 2008, we control a total of approximately 252,000 net acres of coalbed methane and oil and gas development rights.

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

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

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and six months ended June 30, 2008 and 2007. This table should be read with the discussion of the results of operations for the periods presented below (in millions).

	Three Months Ended June 30,			Six Months Ended June 30,		
	2008	2007	Change	2008	2007	Change
Gas sales.....	\$ 20.7	\$ 13.4	54%	\$ 36.3	\$ 25.3	43%
Production expenses.....	\$ 5.3	\$ 5.1	4%	\$ 10.5	\$ 10.3	2%
Net sales volumes (Mmcf) .....	1,856	1,761	5%	3,727	3,467	7%
Average natural gas sales price (per Mcf).....	\$ 11.15	\$ 7.63	46%	\$ 9.73	\$ 7.29	33%

As a result of both the increased gas sales volumes and prices, gas sales revenue for the three and six months ended June 30, 2008 are up 54% and 43%, respectively.

## Recent Developments

Operational activity during the three and six months ended June 30, 2008, include the following:

**Pond Creek** - We drilled two wells and connected four new wells to sales in the second quarter and have drilled five wells and connected six wells to sales in the first 6 months of 2008 giving us a total of 224 productive wells in the Pond Creek field. Subject to the completion of required permitting and acquisition of certain right-of-way agreements, 16 additional new wells are planned to be drilled and placed into sales in the last six months of 2008. Net gas sales increased to 13.4 MMcf per day for the three months ended June 30, 2008, as compared to 12.2 MMcf per day for the three months ended June 30, 2007. Net gas sales increased to 13.4 MMcf per day for the six months ended June 30, 2008, as compared to 12.0 MMcf per day for the six months ended June 30, 2007.

**Lasher** - Production testing continued on three previously drilled wells and four additional wells have been completed to begin the initial dewatering process. A total of 13 wells were drilled in the second quarter of 2008 and two more wells will be drilled in October. Water and gas gathering systems and the high-pressure pipeline that will be used to transport the natural gas to the market are currently being installed. Initial gas sales are expected to begin by the end of the third quarter.

Gurnee – One new well was drilled and connected to sales during the first six months of 2008 bringing the total productive wells to 235. Production testing of two test wells west of the Cahaba River is continuing with encouraging results. Four additional new wells are planned to be drilled on the east side of the Cahaba River in the third quarter of 2008. Net gas sales were 6.0 MMcf per day and 6.1 MMcf per day, respectively, for the three and six months ended June 30, 2008, as compared to 6.0 MMcf per day and 6.0 MMcf per day, respectively, for the three and six months ended June 30, 2007, and will probably remain relatively flat until the remaining wells that we plan to drill in 2008 are placed into production. We have initiated discussions with another operator in the area concerning joint development of the west side of the river and believe that we will achieve efficiencies through these joint efforts.

Garden City – During the first six months of 2008 we have drilled two additional coreholes and the eighth corehole on this prospect is in progress. We also drilled the first horizontal well and one additional vertical well in the second quarter of 2008 bringing the total number of wells drilled on the prospect to five. We plan to conduct a multi-stage fracture stimulation completion on the horizontal well in the third quarter and we recently completed the vertical well and initial production testing has begun. We also refraced the first two wells drilled on the prospect in 2007. In addition, a compressor and pipeline have been installed and three of the wells will be connected to sales in the third quarter of 2008 to facilitate longer term testing. The permitting process has also begun on two additional horizontal wells to be drilled in 2008. We are continuing to expand our leasehold position which is now approximately 77,000 acres in this area.

Peace River – The 2008 capital expenditure plan for Peace River is proceeding according to plan. The facilities and location construction is continuing and all wells have been permitted. Drilling of the five planned wells has commenced and will be completed in the third quarter. A total of eight wells are planned to be on production by year-end, at which time initial proved reserves are expected to be booked for this project.

#### *Property Conveyance and Dispute*

We had previously entered into an agreement to sell our interests in a property, subject to a preferential right to purchase held by another party, which the other party subsequently exercised. A dispute arose as to whether the preferential right to purchase applied to the interests we own in this property. We asserted that the preferential right to purchase did not apply, and that we were entitled to retain all remaining interests we own in the property. We believe we have reached an agreement to assign ownership of the property. The unresolved issue in this dispute relates to the correct application of interest to the sums owed between the parties. As of June 30, 2008, we have estimated the settlement amount to be approximately \$220 thousand and have accrued a liability in that amount as a purchase price adjustment. Although we cannot predict the ultimate outcome at this time, we believe that the actual settlement will not be materially different than the amount we have accrued at June 30, 2008. The proved reserves being conveyed represent less than 1% of our total proved reserves and the related production is approximately 900 Mcf per day.

#### **Critical Accounting Policies**

The preparation of financial statements in conformity with generally accepted accounting principles in the United States 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 changes to our critical accounting policies during the three and six months ended June 30, 2008. We have included additional critical accounting policy information not included in the “Critical Accounting Policies” section of our Annual Report on Form 10-K for the year ended December 31, 2007 in order to expand our revenue recognition accounting policy to include gas balancing.

**Revenue Recognition and Gas Balancing.** We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue whereby revenues, net of royalties, are recognized as the production is sold to purchaser. The amount of gas sold may differ from the amount to which the Company is entitled based on its working interest or net revenue interest in the properties. We typically do not have any significant producer gas imbalance positions because we own 100% working interest in the majority of our properties. A ready market for natural gas allows us to sell our natural gas shortly after production at various pipeline receipt points at which time title and risk of loss transfers to the buyer. Revenue is recorded when title is transferred based on our nominations and net revenue interests. Pipeline imbalances occur when our production delivered into the pipeline varies from the gas we nominated for sale. Pipeline imbalances are settled with cash approximately thirty days from date of production and are recorded as a reduction of revenue or increase of revenue depending upon whether we are over-delivered or under-delivered.

Settlements of gas sales occur after the month in which the gas was produced. We estimate and accrue for the value of these sales using information available at the time financial statements are generated. Differences are reflected in the accounting period during which payments are received from the purchaser.

### Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and six months ended June 30, 2008 and 2007. This table should be read with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Gas sales.....	\$ 20,701	\$ 13,439	\$ 36,282	\$ 25,287
Lease operating expenses .....	\$ 3,640	\$ 3,424	\$ 7,392	\$ 6,794
Compression and transportation expenses.....	1,005	1,355	2,048	2,868
Production taxes .....	634	317	1,056	598
Total production expenses.....	\$ 5,279	\$ 5,096	\$ 10,496	\$ 10,260
Net sales volumes (MMcf) .....	1,856	1,761	3,727	3,467
Pond Creek field.....	1,223	1,110	2,446	2,176
Gurnee field.....	550	548	1,109	1,088
Per Mcf data (\$/Mcf):				
Average natural gas sales price .....	\$ 11.15	\$ 7.63	\$ 9.73	\$ 7.29
Average natural gas sales price realized(1) .....	\$ 10.35	\$ 7.66	\$ 9.57	\$ 7.67
Lease operating expenses .....	\$ 1.96	\$ 1.94	\$ 1.98	\$ 1.96
Pond Creek field.....	\$ 1.53	\$ 1.72	\$ 1.57	\$ 1.70
Gurnee field.....	\$ 3.22	\$ 2.75	\$ 3.20	\$ 2.84
Compression and transportation expenses.....	\$ 0.54	\$ 0.77	\$ 0.55	\$ 0.83
Pond Creek field.....	\$ 0.57	\$ 1.01	\$ 0.61	\$ 1.09
Gurnee field.....	\$ 0.56	\$ 0.40	\$ 0.52	\$ 0.43
Production taxes .....	\$ 0.34	\$ 0.18	\$ 0.29	\$ 0.17
Pond Creek field.....	\$ 0.17	\$ 0.01	\$ 0.12	\$ 0.02
Gurnee field.....	\$ 0.66	\$ 0.47	\$ 0.59	\$ 0.44
Total production expenses.....	\$ 2.84	\$ 2.89	\$ 2.82	\$ 2.96
Pond Creek field.....	\$ 2.27	\$ 2.74	\$ 2.30	\$ 2.81
Gurnee field.....	\$ 4.44	\$ 3.62	\$ 4.31	\$ 3.71
Depreciation, depletion and amortization.....	\$ 1.31	\$ 1.29	\$ 1.31	\$ 1.25

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

### Results of Operations

#### Three Months Ended June 30, 2008 compared with Three Months Ended June 30, 2007

The following are selected items derived from our consolidated statement of operations and their percentage changes from the comparable period are presented below.

	Three Months Ended June 30,		
	2008	2007	Change
Gas sales .....	\$ 20,701	\$ 13,439	54%
Lease operating expenses.....	\$ 3,640	\$ 3,424	6%
Compression expense.....	\$ 733	\$ 709	4%
Transportation expense .....	\$ 272	\$ 646	(58)%
Production taxes.....	\$ 634	\$ 317	100%
Depreciation, depletion and amortization .....	\$ 2,489	\$ 2,265	10%
General and administrative .....	\$ 2,887	\$ 2,227	30%
Realized losses (gains) on derivative contracts.....	\$ 1,493	\$ (50)	NM

	Three Months Ended June 30,		
	2008	2007	Change
	(in thousands)		
Unrealized losses (gains) from the change in market value of open derivative contracts.....	\$ 12,098	\$ (1,861)	NM
Interest expense, net of amounts capitalized.....	\$ 1,117	\$ 1,260	(11)%
Income tax (benefit) expense.....	\$ (1,235)	\$ 1,893	NM
Discontinued operations.....	\$ —	\$ 45	NM

NM-Not Meaningful

*Gas sales.* Gas sales increased by \$7.27 million, or 54%, to \$20.70 million compared to the prior year quarter. The increase in gas sales was a result of both increased gas prices and production. Production increased 5% and average gas prices increased 46%, excluding hedging transactions. The \$7.27 million increase in gas sales consisted of a \$6.54 million increase in prices and a \$0.73 million increase in production. The increase in production was principally attributable to the continued development activities at our Pond Creek and Gurnee fields.

*Lease operating expenses.* Lease operating expenses increased by \$0.22 million, or 6%, to \$3.64 million compared to the prior year quarter. The increase in lease operating expenses consisted of \$0.19 million increase in production and \$0.03 million increase in costs. The increase in costs is due to well treatments and well servicing and higher production overhead rates.

*Compression expense.* Compression expenses increased by 4% compared to the same period in the prior year, which is consistent with a 5% increase in production compared to the same period in the prior year.

*Transportation expense.* Transportation expenses decreased by \$0.37 million, or 58%, to \$0.27 million compared to the prior year quarter. The \$0.37 million decrease was primarily comprised of a decrease in transportation expenses resulting from the commencement of transportation on our own system from the Pond Creek field and the temporary release of a portion of our firm capacity commitments related to our Pond Creek field.

*Production taxes.* Production taxes increased by \$0.32 million, or 100%, to \$0.63 million compared to the prior year quarter. The increase in production taxes is due to the phase-in of the state taxes on production of natural gas in our Pond Creek field, higher gas prices and increased production.

*Depreciation, depletion and amortization.* Depreciation, depletion and amortization increased by \$0.22 million, or 10%, to \$2.49 million compared to the prior year quarter. The depreciation, depletion and amortization increase consisted of a \$0.12 million increase in production and a \$0.10 million decrease in the depletion rate.

*General and administrative.* General and administrative expenses increased by \$0.66 million, or 30%, to \$2.89 million compared to the prior year quarter. The primary drivers for the increased general and administrative expenses were legal costs related to our current litigation and employee expenses. Employee expenses increased as a result of increased headcount causing higher employee related costs.

*Realized losses (gains) on derivative contracts.* Realized losses on derivative contracts were \$1.50 million in the current year quarter as compared to \$0.05 million in realized gains in the prior year quarter. Realized losses represent cash settlements paid to the counterparty, while realized gains represent cash settlements paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

*Unrealized losses (gains) from the change in market value of open derivative contracts.* Unrealized losses on derivative contracts were \$12.10 million in the current year quarter as compared to \$1.86 million in unrealized gains in the prior year quarter. Unrealized losses and gains are non-cash transactions that occur when the corresponding natural gas derivative contract asset or liability are marked to market at the end of each reporting period. The loss was a result of the decreased estimated fair value of our natural gas derivative contracts resulting from increased natural gas prices.

*Interest expense (net of amounts capitalized).* Interest expense (net of amounts capitalized) decreased by \$0.14 million to \$1.12 million compared to the prior year quarter. Gross interest expense for the quarter was \$1.21 million net of \$0.09 million capitalized. Gross interest expense decreased 12.9% from the prior year quarter due to gains on the interest rate swaps, while capitalized interest decreased 27.7% from the prior year quarter due to a decrease in capital expenditures from the prior year quarter.

*Income tax (benefit) expense.* Income tax benefit was \$1.24 million in the current quarter as compared to an expense of \$1.89 million in the prior year quarter. The income tax benefit was due to a pretax loss compared to pretax income in the prior year quarter. In addition, the effective tax rate for the current quarter decreased to 28.0% from 39.1% in the comparable prior year quarter. The decrease in the effective tax rate of 11.1% from the prior year quarter was due to the valuation of uncertain portions of our net operating loss carryforwards.

*Discontinued operations.* In September 2007, we discontinued the third party natural gas marketing business and second reportable segment that had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting our third party marketing business, we are treating these activities as discontinued operations for all the periods presented.

**Six Months Ended June 30, 2008 compared with Six Months Ended June 30, 2007**

The following are selected items derived from our consolidated statement of operations and their percentage changes from the comparable period are presented below.

	Six Months Ended June 30,		
	2008	2007	Change
	(in thousands)		
Gas sales .....	\$ 36,282	\$ 25,287	43%
Lease operating expenses.....	\$ 7,392	\$ 6,794	9%
Compression expense.....	\$ 1,430	\$ 1,363	5%
Transportation expense .....	\$ 618	\$ 1,505	(59)%
Production taxes.....	\$ 1,056	\$ 598	77%
Depreciation, depletion and amortization .....	\$ 4,949	\$ 4,341	14%
General and administrative .....	\$ 5,380	\$ 4,504	19%
Realized losses (gains) on derivative contracts.....	\$ 631	\$ (1,297)	NM
Unrealized losses from the change in market value of open derivative contracts.....	\$ 20,745	\$ 2,713	NM
Interest expense, net of amounts capitalized.....	\$ 2,420	\$ 2,135	13%
Income tax (benefit) expense .....	\$ (2,469)	\$ 1,396	NM
Discontinued operations.....	\$ —	\$ 121	NM

NM-Not Meaningful

*Gas sales.* Gas sales increased by \$11.00 million, or 43%, to \$36.28 million compared to the prior year period. The increase in gas sales was a result of both increased gas prices and production. Production increased 7% and average gas prices increased 33%, excluding hedging transactions. The \$11.00 million increase in gas sales consisted of a \$9.10 million increase in prices and a \$1.90 million increase in production. The increase in production was principally attributable to the continued development activities at our Pond Creek and Gurnee fields.

*Lease operating expenses.* Lease operating expenses increased by \$0.60 million, or 9%, to \$7.39 million compared to the prior year period. The increase in lease operating expenses consisted of \$0.51 million increase in production and \$0.09 million increase in costs. The increase in costs is due to well treatments and well servicing and higher production overhead rates.

*Compression expense.* Compression expenses increased by 5% compared to the same period in the prior year, which is consistent with a 7% increase in production compared to the same period in the prior year.

*Transportation expense.* Transportation expenses decreased by \$0.89 million, or 59%, to \$0.62 million compared to the prior year period. The \$0.37 million decrease was primarily comprised of a decrease in transportation expenses resulting from the commencement of transportation on our own system from the Pond Creek field and the temporary release of a portion of our firm capacity commitments related to our Pond Creek field.

*Production taxes.* Production taxes increased by \$0.46 million, or 77%, to \$1.06 million compared to the prior year period. The increase in production taxes is due to the phase-in of the state taxes on production of natural gas in our Pond Creek field, higher gas prices and increased production.

*Depreciation, depletion and amortization.* Depreciation, depletion and amortization increased by \$0.61 million, or 14%, to \$4.95 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of a \$0.33 million increase in production and a \$0.28 million decrease in the depletion rate.

*General and administrative.* General and administrative expenses increased by \$0.88 million, or 19%, to \$5.4 million compared to the prior year period. The primary drivers for the increased general and administrative expenses were legal costs related to our current litigation and employee expenses. Employee expenses increased as a result of increased headcount causing higher employee related costs.

*Realized losses (gains) on derivative contracts.* Realized losses on derivative contracts were \$0.63 million in the current year period as compared to \$1.30 million in realized gains in the prior year period. Realized losses represent cash settlements paid to the counterparty, while realized gains represent cash settlements paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

*Unrealized losses from the change in market value of open derivative contracts.* Unrealized losses on derivative contracts were \$20.75 million in the current year period as compared to \$2.71 million in unrealized losses in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding natural gas derivative contract asset or liability are marked to market at the end of each reporting period. The loss was a result of the decreased estimated fair value of our natural gas derivative contracts resulting from increased natural gas prices.

*Interest expense (net of amounts capitalized).* Interest expense (net of amounts capitalized) increased by \$0.29 million to \$2.42 million compared to the prior year period. Gross interest expense for the period was \$2.60 million net of \$0.18 million capitalized. Gross interest expense increased 13.3% from the prior year period due to an increase in the average outstanding balance of the revolving credit facility, while capitalized interest decreased 59.4% from the prior year period due to a decrease in capital expenditures from the prior year period.

*Income tax (benefit) expense.* Income tax benefit was \$2.47 million in the current period as compared to an expense of \$1.40 million in the prior year period. The income tax benefit was due to a pretax loss compared to pretax income in the prior year period. In addition, the effective tax rate for the current period decreased to 31.7% from 43.0% in the comparable prior year period. The decrease in the effective tax rate of 11.3% from the prior year period was due to the valuation of uncertain portions of our net operating loss carryforwards.

*Discontinued operations.* In September 2007, we discontinued the third party natural gas marketing business and second reportable segment that had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting our third party marketing business, we are treating these activities as discontinued operations for all the periods presented.

## **Liquidity and Capital Resources**

### ***Cash Flows and Liquidity***

Cash flows from operations for the six months ended June 30, 2008 and 2007 were \$17.6 million and \$10.8 million, respectively. Cash flows from operations of \$17.6 million for the six months ended June 30, 2008, combined together with net cash provided by financing activities of \$3.5 million, were sufficient to fund net cash used in investing activities of \$18.5 million, which primarily includes capital expenditures for the exploration and development of our gas properties. Net cash provided by financing activities was related to credit facility net borrowings.

As of June 30, 2008 and December 31, 2007, we had working capital deficits of approximately \$10.0 million and \$2.1 million, respectively. At June 30, 2008, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficits, which were primarily the result of unrealized losses on derivative contracts of \$13.8 million.

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our credit facility and proceeds from potential future securities offerings will provide the ability to develop our existing properties and conduct exploration on our unevaluated properties.

If natural gas prices decrease significantly for an extended period, our ability to finance our planned capital expenditures could be negatively affected. Furthermore, amounts available for borrowing under our revolving credit facility

are largely dependent on our level of estimated proved reserves and current natural gas prices. If either our estimated proved reserves or natural gas prices decrease, the amount available for us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated, if the amounts available for borrowing under our revolving credit facility are reduced, or if we are unable to sell equity at acceptable prices, we may be forced to defer planned capital expenditures.

### ***Price Risk Management Activities***

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

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

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

### ***Commodity Price Risk and Related Hedging Activities.***

At June 30, 2008, we had the following natural gas collar positions:

<b>Period</b>	<b>Volume (MMBtu)</b>	<b>Sold Ceiling</b>	<b>Bought Floor</b>	<b>Sold Floor</b>
July through October 2008 .....	984,000	\$ 10.50	\$ 7.00	\$ 5.00
November 2008 through March 2009.....	906,000	\$ 11.00	\$ 8.50	\$ 6.25
November 2008 through March 2009.....	906,000	\$ 11.00	\$ 8.84	\$ 6.00
April through October 2009.....	1,284,000	\$ 10.00	\$ 7.50	\$ 5.25
April through October 2009.....	1,284,000	\$ 10.00	\$ 8.50	\$ 6.50
November 2009 through March 2010.....	906,000	\$ 11.20	\$ 9.50	\$ 7.00

At June 30, 2008, the Company had the following natural gas swap position:

<b>Period</b>	<b>Volume (MMBtu)</b>	<b>Price</b>
July through October 2008 .....	492,000	\$ 8.00

### ***Interest Rate Risks and Related Hedging Activities***

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS No. 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At June 30, 2008, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate	Notional amount
Floating-to-fixed swap.....	12/14/2007	12/14/2010	3.863%(1)	\$ 15,000,000
Floating-to-fixed swap.....	1/3/2008	1/4/2010	3.950%(1)	\$ 10,000,000
Floating-to-fixed swap.....	3/25/2008	3/25/2010	2.380%(1)	\$ 10,000,000
Floating-to-fixed swap.....	5/13/2008	5/13/2010	3.069%(1)	\$ 5,000,000

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

For the three and six months ended June 30, 2008, we recognized no ineffective portion of our cash flow hedges.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. SFAS 157 clarifies that a fair value measurement for a 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 liabilities stated below. This consideration involved discounting our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both at June 30, 2008. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

- *Natural Gas Hedges* – In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our credit standing are used to discount future cash flows.
- *Interest Rate Swaps* – In order to estimate the fair value of our interest rate swaps, we use a yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available Money Market rates and Interest Rate swap market data. To extrapolate future cash flows, discount factors incorporating our credit standing are used to discount future cash flows.

Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our derivative instruments at June 30, 2008 and December 31, 2007 were as follows:

	June 30, 2008	December 31, 2007
Interest rate swap - asset.....	\$ 257,188	\$ 10,884
Natural gas hedge - asset.....	—	2,326,791
Total derivative assets.....	\$ 257,188	\$ 2,337,675
Interest rate swap - liability.....	\$ 253,897	\$ —
Natural gas hedge liability.....	18,417,801	—
Total derivative liabilities.....	\$ 18,671,698	\$ —

## Capital Expenditures and Capital Resources

The development of CBM fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, and the timing and volume of initial

and subsequent natural gas production. We estimate total capital expenditures in 2008 will be approximately \$57.0 million as compared to \$59.8 million expended in 2007. The current year budget includes approximately \$43.0 million for development, \$6.0 million for exploration and evaluation, \$4.0 million for leasehold and \$4.0 million for other capitalized costs. Approximately \$25.0 million of the 2008 capital budget is allocated to the Pond Creek and Lasher fields in Virginia and West Virginia; \$14.0 million is allocated to the Gurnee field and the Garden City Chattanooga Shale prospect in Alabama; and \$10.0 million is allocated to the Peace River field in British Columbia.

The following represents total capital expenditures for the six months ended June 30, 2008 (in millions):

Pond Creek .....	\$	4.0
Lasher .....		7.4
Gurnee .....		2.5
Peace River .....		1.1
Garden City .....		4.1
Other .....		2.1
Total.....	\$	<u>21.2</u>

### Revolving Credit Facility

In June 2006, we entered into a \$180 million amended and restated credit agreement with Bank of America, N.A., as agent, and other lenders. Availability under our credit agreement is subject to a borrowing base, which is currently set at \$180 million. Our credit agreement provides for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent's base rate or the federal funds rate plus one half of one percent) or the London Interbank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Borrowings under our credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under our credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our borrowing base) to our consolidated current liabilities is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio of consolidated EBITDA for the four preceding quarters at the end of each fiscal quarter to the sum of our consolidated net interest expense for the same period plus letter of credit fees accruing during such quarter is not permitted to be less than 2.75 to 1. Consolidated EBITDA, as defined in the amended credit agreement, excludes other non-cash charges deducted in determining net income (loss), which would include unrealized losses from the change in the market value of open derivative contracts. In addition, we are subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. A breach of any of the covenants imposed on us by the terms of our revolving credit facility, including the financial covenants, could result in a default under such indebtedness. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business. As of June 30, 2008, we were in compliance with all of the covenants in the credit agreement.

In addition, the borrowing base under our revolving credit facility is redetermined semi-annually and may be redetermined at other times upon request by the lenders under certain circumstances. Redeterminations are based upon a number of factors, including estimated future natural gas prices and estimated future production levels. Based upon our December 31, 2007 reserve report, the borrowing base was reaffirmed at \$180 million as of February 29, 2008. The next redetermination is scheduled to occur on or before November 1, 2008 based upon our internal reserve report as of June 30, 2008. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the revolving credit facility and an acceleration of our indebtedness. At June 30, 2008, we had \$99.5 million outstanding under our revolving credit facility. Interest on the borrowings averaged 3.90% per annum. Borrowing availability at June 30, 2008 was \$80.5 million.

### Contractual Commitments

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

## Discontinued Operations

As of September 30, 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result, we are treating our third party marketing activities as a discontinued operation for all the periods presented.

The marketing activities of Shamrock Energy LLC have been transitioned to GeoMet, Inc without disruption in the marketing of our gas, and we do not expect to incur significant liabilities or sell any assets in connection with discontinuing this business. As a result, the discontinued operations have an insignificant impact on our cash flows.

## Recent Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard No. 157, "Fair Value Measurements" ("SFAS 157"). SFAS 157 is effective for fiscal years beginning after November 15, 2007. Effective January 1, 2008, GeoMet, Inc. adopted SFAS 157, which provides a framework for measuring fair value under accounting principles generally accepted in the United States. SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are observed from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of SFAS 157 in Note 6 — Derivative Instruments and Hedging Activities.

On February 15, 2007, the FASB issued SFAS Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB 115" ("SFAS 159"). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of SFAS 159 are elective; however, the amendment to FASB 115, "Accounting for Certain Investments in Debt and Equity Securities," applies to all entities that own trading and available-for-sale securities. The fair value option created by SFAS 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. SFAS 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Effective January 1, 2008, we adopted SFAS 159. We did not elect the fair value option for any of our assets or liabilities that did not already require such treatment under other authoritative literature.

In March 2008, the FASB issued SFAS Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133" ("SFAS 161"). This standard changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact of SFAS 161 on our disclosure relating to derivative instruments and hedging activities. The statement only provides for enhanced disclosure. Therefore, adoption will have no impact on our financial position or results of operations.

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

*Commodity 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. At June 30, 2008, a 10% decrease in the prices received for natural gas production would have had an approximate \$6.8 million impact on our revenues.

*Interest Rate Risk.* We have long-term debt subject to the risk of loss associated with movements in interest rates. At June 30, 2008, we had \$99.5 million outstanding under our revolving credit facility. Interest on the borrowings averaged

3.90% per annum. Borrowing availability at June 30, 2008 was \$80.5 million. All of the debt outstanding under our revolving credit facility accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance outstanding under our revolving credit facility at June 30, 2008, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately \$0.6 million. \$40 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swaps we have in place.

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

#### **Item 4. Controls and Procedures**

##### **Evaluation of Disclosure Controls and Procedures**

In accordance with Exchange Act Rule 13a-15(e) and 15d-15(e), we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2008 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

##### **Changes in Internal Controls Over Financial Reporting**

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

## **Part II. OTHER INFORMATION**

#### **Item 1. Legal Proceedings**

From time to time we may be 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 outcome will have a material adverse effect on our financial condition, results of operations or operating cash flows, except as described below.

##### **CNX Surface Use Disputes**

We constructed a 12-mile gathering line in the Pond Creek field, a portion of which traverses a right-of-way granted to us by Pocahontas Mining Limited Liability Company ("PMC") in Buchanan County, Virginia. Our Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC ("CNX"), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. No amounts were deposited into escrow. On November 5, 2007, the Virginia Supreme Court accepted PMC's and our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the

PMC property. We presented oral arguments before the Virginia Supreme Court on June 2, 2008 and expect a decision by early September, 2008. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the property. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. No gas from the Pond Creek field has ever been shut in as a result of the CNX surface disputes. We believe it is unlikely we will be prevented from transporting our gas to market through our Pond Creek gathering line if we do not prevail in our CNX surface dispute. However, in such event, we believe we have alternatives available to deliver our gas to market. Such alternatives could require the expenditure of material amounts and it is possible we may be unable to deliver our gas from the Pond Creek field to market for some period of time.

### CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company (“Island Creek”), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX’s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX’s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX’s position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we have filed an amended petition that restates with specificity our claims against CNX and Island Creek, names Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as additional defendants, and seeks actual damages of \$385.6 million. We are seeking treble damages for the alleged violations of the Virginia Antitrust Act, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

### Environmental and Regulatory

As of June 30, 2008, 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 have been no material changes from the risk factors disclosed in the “Risk Factors” section of our Annual Report on Form 10-K for the year ended December 31, 2007.

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

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
04/01/08 – 04/30/08.....	—	—	—	—
05/01/08 – 05/31/08.....	—	—	—	—
06/01/08 – 06/30/08.....	2,604	\$ 8.97	—	—

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

**Item 3. Defaults Upon Senior Securities.**

None.

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

None.

**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.

## SIGNATURES

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

### **GeoMet, Inc.**

Date: August 8, 2008

By /s/ William C. Rankin

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

## INDEX TO EXHIBITS

Exhibit Number	Exhibits
31.1*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32*	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).

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\* Attached hereto

**CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, William C. Rankin, certify that

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended June 30, 2008 of GeoMet, Inc. (“registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 8, 2008

By           /s/ WILLIAM C. RANKIN            
**William C. Rankin,**  
**Chief Financial Officer**

**CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, J. Darby Seré, certify that

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended June 30, 2008 of GeoMet, Inc. (“registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 8, 2008

By \_\_\_\_\_ /s/ J. DARBY SERÉ  
**J. Darby Seré,**  
**Chief Executive Officer**

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

In connection with the Quarterly Report of GeoMet, Inc. (the “Company”) for the quarter ended June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, J. Darby Seré, Chief Executive Officer, and I, William C. Rankin, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. DARBY SERÉ

/s/ WILLIAM C. RANKIN

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**J. Darby Seré**  
**Chief Executive Officer**  
**August 8, 2008**

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**William C. Rankin**  
**Chief Financial Officer**  
**August 8, 2008**

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