GeoMet, Inc.
Form 10-Q
November 07, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 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

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

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

N/A

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

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

Indicate by check mark whether the registrant 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	x
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 x No

As of October 1, 2008 there were 39,288,746 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

(Unaudited)

	September 30, 2008	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,953,294	$ 1,540,516
Accounts receivable	6,514,504	4,881,397
Inventory	4,218,727	2,355,595
Derivative asset	2,740,067	2,247,248
Other current assets	684,439	484,341
Total current assets	16,111,031	11,509,097
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	399,415,289	370,404,336
Unevaluated gas properties, not subject to amortization	37,821,387	25,174,764
Other property and equipment	3,113,575	2,536,619
Total property and equipment	440,350,251	398,115,719
Less accumulated depreciation, depletion, and amortization	(39,292,588)	(31,886,633)
Property and equipment net	401,057,663	366,229,086
Other noncurrent assets:		
Derivative asset	554,918	90,427
Other	690,295	848,816
Total other noncurrent assets	1,245,213	939,243
TOTAL ASSETS	$ 418,413,907	$ 378,677,426
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 15,910,061	$ 7,536,274
Accrued liabilities	2,834,637	5,087,871
Deferred income taxes	937,455	770,675
Derivative liability	187,285	
Asset retirement liability	122,092	74,387
Current portion of long-term debt	110,215	102,586
Total current liabilities	20,101,745	13,571,793
Long-term debt	108,636,044	96,729,722
Derivative liability	83,991	
Asset retirement liability	4,218,317	2,915,855
Other long-term accrued liabilities	114,035	138,471
Deferred income taxes	54,554,275	46,645,879
TOTAL LIABILITIES	187,708,407	160,001,720

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 39,288,746 and 38,962,359 at September 30, 2008 and December 31, 2007, respectively	39,289	38,962
Paid-in capital	188,444,750	187,550,484
Accumulated other comprehensive income	1,374,855	2,394,001
Retained earnings	41,072,118	28,909,363
Less notes receivable	(225,512)	(217,104)
TOTAL STOCKHOLDERS EQUITY	230,705,500	218,675,706
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 418,413,907	$ 378,677,426

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Revenues:				
Gas sales	$ 18,674,209	$ 11,303,198	$ 54,956,315	$ 36,590,259
Operating fees and other	146,093	341,099	647,250	957,098
Total revenues	18,820,302	11,644,297	55,603,565	37,547,357
Expenses:				
Lease operating expense	3,475,373	3,559,786	10,866,943	10,353,430
Compression and transportation expense	1,129,425	1,165,745	3,177,620	4,033,311
Production taxes	599,237	260,125	1,655,282	857,806
Depreciation, depletion and amortization	2,523,737	2,346,875	7,472,332	6,687,649
General and administrative	2,098,060	2,538,131	7,477,767	7,041,819
Realized losses (gains) on derivative contracts	1,389,952	(1,227,572)	2,021,188	(2,524,102)
Unrealized (gains) losses on derivative contracts	(21,564,961)	(463,960)	(820,369)	2,249,269
Total operating expenses	(10,349,177)	8,179,130	31,850,763	28,699,182
Operating income from continuing operations	29,169,479	3,465,167	23,752,802	8,848,175
Other income (expense):				
Interest income	15,767	6,893	35,830	31,991
Interest expense (net of amounts capitalized)	(1,117,553)	(1,448,065)	(3,538,022)	(3,583,481)
Other	18,047	(26,569)	47,390	(51,189)
Total other income (expense)	(1,083,739)	(1,467,741)	(3,454,802)	(3,602,679)
Income before income taxes and discontinued operations	28,085,740	1,997,426	20,298,000	5,245,496
Income tax expense	10,604,417	453,973	8,135,244	1,850,159
Income from continuing operations	17,481,323	1,543,453	12,162,756	3,395,337
Discontinued operations, net of tax		44,618		165,512
Net income	$ 17,481,323	$ 1,588,071	$ 12,162,756	$ 3,560,849
Earnings per share:				
Income from continuing operations				
Basic	$ 0.45	$ 0.04	$ 0.31	$ 0.09
Diluted	$ 0.44	$ 0.04	$ 0.31	$ 0.09
Discontinued operations				
Basic	$ 0.00	$ 0.00	$ 0.00	$ 0.00
Diluted	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Net income				
Basic	$ 0.45	$ 0.04	$ 0.31	$ 0.09
Diluted	$ 0.44	$ 0.04	$ 0.31	$ 0.09
Weighted average number of common shares:				
Basic	38,872,218	38,726,595	38,821,764	38,706,546
Diluted	39,838,826	39,593,615	39,714,176	39,634,403

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive Income

(Unaudited)

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Net income	$ 17,481,323	$ 1,588,071	$ 12,162,756	$ 3,560,849
Gain (loss) on foreign currency translation adjustment, net of tax	(198,303)	1,021,963	(530,187)	2,388,023
Loss on interest rate swap, net of tax	(75,309)		(80,495)	
Other comprehensive income	$ 17,207,711	$ 2,610,034	$ 11,552,074	$ 5,948,872

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2008	2007
Cash flows provided by operating activities:		
Net income	$ 12,162,756	$ 3,560,849
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	7,472,332	6,814,572
Amortization of debt issuance costs	129,458	105,475
Deferred income tax expense	8,122,744	1,933,131
Unrealized (gains) losses from the change in market value of open derivative contracts	(820,369)	2,249,269
Stock-based compensation	485,757	257,393
Gain (loss) on sale of assets	20,512	(49,572)
Accretion expense	257,528	156,753
Changes in operating assets and liabilities:		
Accounts receivable	(1,663,697)	6,740,910
Other current assets	(2,069,906)	(305,907)
Accounts payable	2,211,140	(5,795,191)
Other accrued liabilities	(1,338,138)	572,049
Net cash provided by operating activities	24,970,117	16,239,731
Cash flows used in investing activities:		
Capital expenditures	(36,567,273)	(45,019,838)
Proceeds from sale of other property and equipment	26,000	97,855
Other assets	28,816	85,489
Net cash used in investing activities	(36,512,457)	(44,836,494)
Cash flows provided by financing activities:		
Treasury stock	(23,359)	(4,382)
Proceeds from exercise of stock options	75,025	198,808
Credit facility borrowings	12,000,000	28,500,000
Proceeds from notes receivable and accrued interest		164,134
Payments on other debt	(86,048)	(78,987)
Net cash provided by financing activities	11,965,618	28,779,573
Effect of exchange rate changes on cash	(10,500)	294,837
Increase in cash and cash equivalents	412,778	477,647
Cash and cash equivalents at beginning of period	1,540,516	1,414,476
Cash and cash equivalents at end of period	$ 1,953,294	$ 1,892,123

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(Unaudited)

Note 1 Organization and Our Business

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

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America. 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 December 2007, the Financial Accounting Standards Board (the FASB) issued Statement of Financial Accounting Standards No. 141R, Business Combinations (Revised 2007) (SFAS 141R), which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. We will evaluate the impact of SFAS No. 141R on our consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

In September 2006, the FASB issued SFAS 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 are 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. We have elected to defer the application of SFAS 157 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 October 10, 2008, the FASB issued Staff Position No. FAS 157-3 (FSP No. 157-3). FSP No. 157-3 clarifies the application of SFAS 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. On January 1, 2009, we will adopt SFAS 157 as it relates to nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired

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property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. We do not expect any significant impact to our consolidated financial statements when we implement SFAS 157 for our existing non-financial assets and liabilities.

On February 15, 2007, the FASB issued SFAS 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 December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements (SFAS 160). SFAS 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires that changes in a parent s ownership interest in a subsidiary be reported as an equity transaction in the consolidated financial statements when it does not result in a change in control of the subsidiary. When a change in a parent s ownership interest results in deconsolidation, a gain or loss should be recognized in the consolidated financial statements. SFAS 160 must be applied prospectively as of January 1, 2009, except for the presentation and disclosure requirements, which are required to be applied retrospectively for all periods presented. The adoption of SFAS 160 will not have a material impact on our results of operations, cash flows or financial positions; however, it could impact future transactions entered into by us.

In March 2008, the FASB issued SFAS 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

Earnings Per Share of Common Stock Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Fully diluted 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 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 September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Income from continuing operations per share:				
Basic-net income per share	$ 0.45	$ 0.04	$ 0.31	$ 0.09
Diluted-net income per share	$ 0.44	$ 0.04	$ 0.31	$ 0.09
Discontinued operations per share:				
Basic-net income per share	$	$	$	$
Diluted-net income per share	$	$	$	$
Net income per share:				
Basic-net income per share	$ 0.45	$ 0.04	$ 0.31	$ 0.09

Diluted-net income per share	$ 0.44	$ 0.04	$ 0.31	$ 0.09
Numerator				
Income from continuing operations	$ 17,481,323	$ 1,543,453	$ 12,162,756	$ 3,395,337
Discontinued operations		44,618		165,512
Net income available to common stockholders	$ 17,481,323	$ 1,588,071	$ 12,162,756	$ 3,560,849
Denominator:				
Weighted average shares outstanding-basic	38,872,218	38,726,595	38,821,764	38,706,546
Add potentially dilutive securities:				
Stock options and non-vested restricted stock	966,608	867,020	892,412	927,857
Weighted average shares and potential dilutive shares outstanding	39,838,826	39,593,615	39,714,176	39,634,403

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Diluted net income per share for the three and nine months ended September 30, 2008 excluded the effect of outstanding options to purchase 673,597 shares because the average market price for the period was less than the exercise price. Diluted net income per share for the three and nine months ended September 30, 2007 excluded the effect of outstanding options to purchase 738,701 and 605,457 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.

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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 all the interests we owned in this property or just the working interests. We filed a declaratory judgment action asserting that the preferential right to purchase applied only to the working interests, and that we were entitled to retain all remaining interests we owned in the property. Following a partial agreement with the other party, we assigned all our remaining interests in the property to that party, effective July 1, 2008. The remaining issue in this case relates to the correct application of interest to the sums owed between the parties. On October 17, 2008, the 116th Judicial District Court of Dallas issued an order requiring us to pay $575,000 to the other party in final settlement of the issue. Consequently, as of September 30, 2008, we have accrued that amount as a liability, representing a purchase price adjustment. We intend to appeal the ruling by the court. 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.

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The following table details the changes to our asset retirement liability for the nine months ended September 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	171,689
Liabilities settled	(121,838)
Accretion	272,389
Revisions in estimates	1,040,212
Foreign currency translation	(12,285)
Asset retirement liability at September 30, 2008	4,340,409
Less: Current portion of liability	(122,092)
Long-term asset retirement liability	$ 4,218,317

Revisions in estimates of our asset retirement liability totaling $1,040,212 were due primarily 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.

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

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
Realized losses (gains) on derivative contracts	$ 1,389,952	$ (1,227,572)	$ 2,021,188	$ (2,524,102)
Unrealized (gains) losses on derivative contracts	(21,564,961)	(463,960)	(820,369)	2,249,269
Total (gains) losses	$ (20,175,009)	$ (1,691,532)	$ 1,200,819	$ (274,833)

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Commodity Price Risk and Related Hedging Activities.

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

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor
October 2008	248,000	$ 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 September 30, 2008, the Company had the following natural gas swap position:

Period	Volume (MMBtu)	Price
October 2008	124,000	$ 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. Accounting for Derivative Instruments and Hedging Activities (SFAS No. l33). 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 September 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 nine months ended September 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. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our credit agreement.

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

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

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 September 30, 2008 and December 31, 2007 were as follows:

	September 30, 2008	December 31, 2007
Interest rate swap - asset	$ 147,825	$ 10,884
Natural gas hedge - asset	3,147,160	2,326,791
Total derivative assets	$ 3,294,985	$ 2,337,675
Interest rate swap - liability	$ 271,276	$
Natural gas hedge liability		
Total derivative liabilities	$ 271,276	$

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 September 30, 2008, we had $108 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $72 million under our $180 million borrowing base. For the three and nine months ended September 30, 2008 we borrowed $38.5 million and $89 million, respectively, and made payments of $30 million and $77 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at 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 September 30, 2008 and December 31, 2007, excluding the effect of our interest rate swaps, were 4.39% and 6.29%, respectively.

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

	September 30, 2008	December 31, 2007
Borrowings under revolving credit facility	$ 108,000,000	$ 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	121,486	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	488,801	528,498
Total debt	108,746,259	96,832,308
Less current maturities included in current liabilities	(110,215)	(102,586)
Total long-term debt	$ 108,636,044	$ 96,729,722

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability, of 1.0 to 1.0, and a rate of consolidated EBITDA 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 September 30, 2008, we were in compliance with all of the covenants in the credit agreement.

Note 8 Common Stock

At September 30, 2008 and December 31, 2007, there were 39,288,746 shares and 38,962,359 shares, respectively, of common stock outstanding. At September 30, 2008 and December 31, 2007, common stock outstanding included 10,432 shares and 7,828 shares, respectively, of treasury stock held by the Company. For the three and nine months ended September 30, 2008, we issued no shares and 44,337 shares, respectively, of common stock upon the exercise of stock options granted under our 2005 Stock Option Plan. 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. In September 2008, we issued 46,694 shares of restricted stock to employees of the Company. The shares of common stock for our independent directors and the restricted stock were issued pursuant to our 2006 Long-Term Incentive Plan. Additionally, for the three and nine months ended September 30, 2008, 32,279 shares and 37,170 shares of restricted stock, respectively, 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 September 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.

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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. In September 2008, we granted 46,694 restricted stock awards with time vesting criteria to certain key employees. During the three and nine months ended September 30, 2008, we recorded stock based compensation cost of $231,484 and $840,768, respectively, of which $14,622 and $41,319, respectively, was allocated to lease operating expenses, $87,123 and $444,032, respectively, to general and administrative expenses, and $129,739 and $355,417, respectively, was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is $2.1 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 1.75 years.

Significant assumptions used in determining the compensation costs of stock options 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 nine months ended September 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	(99,361)	$ 4.52		
Exercised	(44,337)	$ 1.69		
Outstanding at September 30, 2008	538,579	$ 7.84	4.49	$ 257,678
Options exercisable at September 30, 2008	304,280	$ 7.47	3.72	$ 239,693

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

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the nine months ended September 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	(30,968)	$ 10.22		
Outstanding at September 30, 2008	1,280,087	$ 3.87	4.57	$ 3,073,664
Options exercisable at September 30, 2008	1,141,131	$ 3.30	4.43	$ 3,057,600

During the nine months ended September 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 nine months ended September 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	300,500	6.34
Vested	(28,391)	7.23
Forfeited	(37,170)	6.80
Non-vested restricted stock at September 30, 2008	408,937	$ 6.61

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On June 15, 2008, 20,800 shares of restricted stock vested. The fair value of the shares that vested on that date was $186,576. On September 20, 2008, 5,591 shares of restricted stock vested. The fair value of the shares that vested on that date was $33,266. On September 24, 2008, 2,000 shares of restricted stock vested. The fair value of the shares that vested on that date was $11,760.

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

Buchanan County Dispute. On September 12, 2008, the Virginia Supreme Court issued its decision in this matter in favor of us and PMC, reversing and remanding the matter to the Buchanan Circuit Court for further action consistent with the decision. The Court held that CNX Gas Company LLC (CNX) does not have the exclusive right to transport gas across the Pocahontas Mining Limited Liability Company (PMC) property and may not prevent uses of the PMC property that do not conflict with the exercise of CNX s rights under its lease. The effect of this ruling is that our pipeline right of way with PMC is valid.

This dispute began during the construction of our 12-mile Pond Creek gathering line, a portion of which traverses a right-of-way granted to us by 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, the lessee of certain minerals underlying the PMC property, had claimed that it had 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 September 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. Oral argument before the Virginia Supreme Court was held on June 2, 2008.

Tazewell County Dispute**.** 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.

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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 in Tazewell County.

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 September 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.

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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 September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Gas marketing revenues	$	$ 4,404,137	$	$ 21,847,934
Purchased gas		(4,346,395)		(21,574,450)
Income before tax		57,742		273,484
Income tax expense		(13,124)		(107,972)
Discontinued operations	$	$ 44,618	$	$ 165,512

Balance Sheet Data:

	September 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 certain states from which we are currently unable to benefit, as well as state income taxes. The Canadian and state 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 September 30, 2009. For tax reporting purposes, we have federal and state NOL s of approximately $77.1 million and $5.7 million, respectively, at September 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.

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

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

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 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 September 30, 2008, we control a total of approximately 230,000 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.

Impact of Current Credit Market Conditions We feel that we are well-positioned for the current credit market environment. We have a healthy balance sheet with nearly $2 million in cash and a debt-to-book capital ratio of 47%. The borrowing base on our revolving credit facility was reaffirmed at $180 million in October 2008. If not extended, our credit facility will mature in January 2011. All of our lenders are currently funding our borrowing requests. Because of our cash flows from operations, we are not as dependent on credit to fund our current capital programs. We believe that our current cash and short-term investment balances, cash generated by operations, and access to our credit facility will be sufficient to meet our operating and capital needs in the foreseeable future.

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

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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2008	2007	Change	2008	2007	Change
Gas sales	$ 18.7	$ 11.3	65%	$ 55.0	$ 36.6	50%
Production expenses	$ 5.2	$ 5.0	4%	$ 15.7	$ 15.2	3%
Net sales volumes (MMcf)	1,821	1,804	1%	5,548	5,271	5%
Average natural gas sales price (per Mcf)	$ 10.26	$ 6.26	64%	$ 9.91	$ 6.94	43%

As a result of both the increased gas sales volumes and prices, gas sales revenue for the three and nine months ended September 30, 2008 are up 65% and 50%, respectively.

Operational Developments

Operational activity during the three and nine months ended September 30, 2008, include the following:

Pond Creek We drilled fifteen and connected seven new wells to sales in the third quarter. We connected eleven wells to sales during the first nine months of 2008 giving us a total of 231 productive wells in the Pond Creek field. Upon completion of required permitting and acquisition of certain right-of-way agreements, five additional new wells are planned to be drilled and twelve new wells placed into sales in the last three months of 2008. Net gas sales increased to 13.6 MMcf per day for the three months ended September 30, 2008, as compared to 12.5 MMcf per day for the three months ended September 30, 2007. Net gas sales increased to 13.5 MMcf per day for the nine months ended September 30, 2008, as compared to 12.2 MMcf per day for the nine months ended September 30, 2007.

Lasher Production testing continued on three previously drilled wells and thirteen wells drilled in the first nine months of 2008 to begin the initial dewatering process. Two additional wells will be completed in the fourth quarter to bring the total number of producing wells to 18. Water and gas gathering systems and the high-pressure pipeline that will be used to transport the natural gas to the market have been installed and the compressor and metering station is in the final stage of completion. Initial gas sales are expected to begin in the fourth quarter. Initial gas sales commenced on October 28, 2008.

Gurnee Five new wells were drilled and connected to sales during the first nine months of 2008 bringing the total number of productive wells to 239. Production testing of two test wells west of the Cahaba River is continuing with encouraging results. Seven additional wells are being drilled on the east side of the Cahaba River, which we expect to place into sales in the fourth quarter of 2008. Net gas sales were 6.1 MMcf per day for the three and nine months ended September 30, 2008, as compared to 6.1 MMcf per day and 6.0 MMcf per day, respectively, for the three and nine months ended September 30, 2007.

Garden City In this Chattanooga shale prospect two vertical wells were re-stimulated and a horizontal well drilled in the second quarter was completed in the third quarter. These three wells were connected to sales in the third quarter with net gas sales averaging 0.2 MMcf per day through September 30, 2008. One additional horizontal well is planned to be drilled and completed in the fourth quarter. Two vertical test wells drilled in the western portion of the prospect are currently shut-in awaiting the identification of adequate water disposal and connection into a gas sales line. Additional activity in the fourth quarter will include evaluating the potential for water disposal.

Peace River The 2008 capital expenditure plan for Peace River is proceeding according to plan. The installation of the facilities is continuing and five new wells have been drilled and completed. The five new wells and three existing 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 all the interests we owned in this property or just the working interests. We filed a declaratory judgment action asserting that the preferential right to purchase applied only to the working interests, and that we were entitled to retain all remaining interests we owned in the property. Following a partial agreement with the other party, we assigned all our remaining interests in the property to that party, effective July 1, 2008. The remaining issue in this case relates to the correct application of interest to the sums owed between the parties. On October 17, 2008, the 116th Judicial District Court of Dallas issued an order requiring us to pay $575,000 to the other party in final settlement of the issue.

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Consequently, as of September 30, 2008, we have accrued that amount as a liability, representing a purchase price adjustment. We intend to appeal the ruling by the court. 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 polices 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 nine months ended September 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.

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Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and nine months ended September 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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Gas sales	$ 18,674	$ 11,303	$ 54,956	$ 36,590
Lease operating expenses	$ 3,475	$ 3,560	$ 10,867	$ 10,353
Compression and transportation expenses	1,129	1,166	3,178	4,033
Production taxes	599	260	1,655	858
Total production expenses	$ 5,203	$ 4,986	$ 15,700	$ 15,244
Net sales volumes (MMcf)	1,821	1,804	5,548	5,271
Pond Creek field	1,252	1,150	3,698	3,326
Gurnee field	558	560	1,667	1,648
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 10.26	$ 6.26	$ 9.91	$ 6.94
Average natural gas sales price realized(1)	$ 9.49	$ 6.95	$ 9.54	$ 7.42
Lease operating expenses	$ 1.91	$ 1.97	$ 1.96	$ 1.96
Pond Creek field	$ 1.46	$ 1.56	$ 1.53	$ 1.65
Gurnee field	$ 2.81	$ 3.13	$ 3.07	$ 2.95
Compression and transportation expenses	$ 0.62	$ 0.65	$ 0.57	$ 0.77
Pond Creek field	$ 0.65	$ 0.80	$ 0.62	$ 1.00
Gurnee field	$ 0.55	$ 0.47	$ 0.53	$ 0.45
Production taxes	$ 0.33	$ 0.14	$ 0.30	$ 0.16
Pond Creek field	$ 0.19	$ 0.01	$ 0.15	$ 0.01
Gurnee field	$ 0.64	$ 0.37	$ 0.60	$ 0.41
Total production expenses	$ 2.86	$ 2.76	$ 2.83	$ 2.89
Pond Creek field	$ 2.30	$ 2.37	$ 2.30	$ 2.66
Gurnee field	$ 4.00	$ 3.97	$ 4.20	$ 3.81
Depreciation, depletion and amortization	$ 1.39	$ 1.30	$ 1.35	$ 1.27

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

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Results of Operations

Three Months Ended September 30, 2008 compared with Three Months Ended September 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 September 30, 2008	2007	Change
	(in thousands)		
Gas sales	$ 18,674	$ 11,303	65%
Lease operating expenses	$ 3,475	$ 3,560	-2%
Compression expense	$ 824	$ 620	33%
Transportation expense	$ 305	$ 546	-44%
Production taxes	$ 599	$ 260	130%
Depreciation, depletion and amortization	$ 2,524	$ 2,347	8%
General and administrative	$ 2,098	$ 2,538	-17%
Realized losses (gains) on derivative contracts	$ 1,390	$ (1,228)	NM
Unrealized gains from the change in market value of open derivative contracts	$ (21,565)	$ (464)	NM
Interest expense, net of amounts capitalized	$ 1,118	$ 1,448	-23%
Income tax expense	$ 10,604	$ 454	NM
Discontinued operations	$	$ 45	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $7.37 million, or 65%, to $18.67 million compared to the prior year quarter. The increase in gas sales was a result of primarily increased gas prices. Production increased 1% and average gas prices increased 64%, excluding hedging transactions. The $7.37 million increase in gas sales consisted of a $7.26 million increase in prices and a $0.11 million increase in production.

Lease operating expenses. Lease operating expenses decreased by $0.09 million, or 2%, to $3.48 million compared to the prior year quarter. The decrease in lease operating expenses consisted of $0.03 million increase in production offset by $0.12 million decrease in costs. The $0.12 million decrease was primarily comprised of a decrease in repair and maintenance expenses for the wells in all of our fields.

Compression expense. Compression expense increased by $0.20 million, or 33%, compared to the same period in the prior year. The increase in compression expense consisted of $0.01 million increase in production and $0.19 million increase in costs. The $0.19 million increase in costs was primarily comprised of an increase in repair and maintenance expenses for the compressors in our Pond Creek field.

Transportation expense. Transportation expenses decreased by $0.24 million, or 44%, to $0.31 million compared to the prior year quarter. The $0.24 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 $0.34 million, or 130%, to $0.60 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 $0.18 million, or 8%, to $2.52 million compared to the prior year quarter. The depreciation, depletion and amortization increase consisted of a $0.02 million increase in production and a $0.15 million decrease in the depletion rate.

General and administrative. General and administrative expenses decreased by $0.44 million, or 17%, to $2.10 million compared to the prior year quarter. The primary drivers for the decreased general and administrative expenses were decreased legal and professional costs.

Realized losses (gains) on derivative contracts. Realized losses on derivative contracts were $1.39 million in the current year quarter as compared to $1.23 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.

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Unrealized gains from the change in market value of open derivative contracts. Unrealized gains on derivative contracts were $21.57 million in the current year quarter as compared to $0.46 million in the prior year quarter. Unrealized 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 gain was a result of the increased estimated fair value of our natural gas derivative contracts resulting from decreased natural gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.33 million to $1.12 million compared to the prior year quarter. Gross interest expense for the quarter was $1.24 million net of $0.12 million capitalized. Gross interest expense decreased 18.8% from the prior year quarter due to lower interest rates, while capitalized interest increased 54.9% from the prior year quarter due to an increase in capital expenditures from the prior year quarter.

Income tax (benefit) expense. Income tax expense was $10.60 million in the current quarter as compared to an expense of $0.45 million in the prior year quarter. The effective tax rate for the current quarter increased to 37.7% from 22.7% in the comparable prior year quarter. The increase in the effective tax rate from the prior year quarter was due to lower state income taxes in the prior year quarter resulting from a state apportionment factor shifting.

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.

Nine Months Ended September 30, 2008 compared with Nine Months Ended September 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.

	Nine Months Ended September 30,		
	2008	2007	Change
		(in thousands)	
Gas sales	$ 54,956	$ 36,590	50%
Lease operating expenses	$ 10,867	$ 10,353	5%
Compression expense	$ 2,254	$ 1,982	14%
Transportation expense	$ 923	$ 2,051	-55%
Production taxes	$ 1,655	$ 858	93%
Depreciation, depletion and amortization	$ 7,472	$ 6,688	12%
General and administrative	$ 7,478	$ 7,042	6%
Realized losses (gains) on derivative contracts	$ 2,021	$ (2,524)	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (820)	$ 2,249	NM
Interest expense, net of amounts capitalized	$ (3,538)	$ (3,583)	-1%
Income tax benefit	$ 8,135	$ 1,850	NM
Discontinued operations	$	$ 166	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $18.37 million, or 50%, to $54.96 million compared to the prior year period. The increase in gas sales was a result of both increased gas prices and production. Production increased 5% and average gas prices increased 43%, excluding hedging transactions. The $18.37 million increase in gas sales consisted of a $16.44 million increase in prices and a $1.93 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 $0.51 million, or 5%, to $10.87 million compared to the prior year period. The increase in lease operating expenses consisted of $0.54 million increase in production offset $0.03 million decrease in costs.

Compression expense. Compression expense increased by $0.27 million, or 14%, compared to the same period in the prior year. The increase in compression expense consisted of $0.10 million increase in production and $0.17 million increase in costs. The $0.17 million increase in costs was primarily comprised of an increase in repair and maintenance expenses for the compressors in our Pond Creek field.

Transportation expense. Transportation expenses decreased by $1.13 million, or 55%, to $0.92 million compared to the prior year period. The $1.13 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 $0.78 million, or 93%, to $1.66 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 $0.78 million, or 12%, to $7.47 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of a $0.36 million increase in production and a $0.42 million decrease in the depletion rate.

General and administrative. General and administrative expenses increased by $0.44 million, or 6%, to $7.48 million compared to the prior year period. The primary driver for the increased general and administrative expenses was 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 $2.02 million in the current year period as compared to $2.52 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 (gains) losses from the change in market value of open derivative contracts. Unrealized gains on derivative contracts were $0.82 million in the current year period as compared to $2.25 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.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.05 million, or 1% to $3.54 million compared to the prior year period. Gross interest expense for the period was $3.84 million net of $0.30 million capitalized. Gross interest expense decreased 6.5% from the prior year period due to lower interest rates, while capitalized interest decreased 42.1% from the prior year period due to a decrease in capital expenditures from the prior year period.

Income tax (benefit) expense. Income tax expense was $8.14 million in the current period as compared to an expense of $1.85 million in the prior year period. The effective tax rate for the current period increased to 39.9% from 35.3% in the comparable prior year period. The increase in the effective tax rate of 4.6% from the prior year period was due to the valuation of uncertain portions of our net operating loss carryforwards and lower state income taxes in the prior year period resulting from a state apportionment factor shifting.

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.

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Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the nine months ended September 30, 2008 and 2007 were $25.0 million and $16.2 million, respectively. Cash flows from operations of $25.0 million for the nine months ended September 30, 2008, combined together with net cash provided by financing activities of $12.0 million, were sufficient to fund net cash used in investing activities of $36.5 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 September 30, 2008, we had a working capital deficit of approximately $4.0 million. At September 30, 2008, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficits. As of December 31, 2007, we had a working capital deficit of approximately $2.1 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.

The recent disruption in the credit markets has had a significant adverse impact on a number of financial institutions. We have reviewed the creditworthiness of the banks and financial institutions with which we maintain our investments. Thus far, our liquidity and financial position have not been impacted, and we do not expect that it will be materially impacted in the future. However, we cannot predict with any certainty the impact of any further disruption in the credit markets.

Price Risk Management Activities

The energy markets have historically been 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.

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Commodity Price Risk and Related Hedging Activities.

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

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor
October 2008	248,000	$ 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 September 30, 2008, the Company had the following natural gas swap position:

Period	Volume (MMBtu)	Price
October 2008	124,000	$ 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 September 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 nine months ended September 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 an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both at September 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

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activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

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

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 September 30, 2008 and December 31, 2007 were as follows:

	September 30, 2008	December 31, 2007
Interest rate swap - asset	$ 147,825	$ 10,884
Natural gas hedge - asset	3,147,160	2,326,791
Total derivative assets	$ 3,294,985	$ 2,337,675
Interest rate swap - liability	$ 271,276	$
Natural gas hedge liability		
Total derivative liabilities	$ 271,276	$

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 $55.9 million as compared to $59.8 million expended in 2007. The current year budget includes approximately $41.9 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 nine months ended September 30, 2008 (in millions):

Pond Creek	$ 11.9
Lasher	10.6
Gurnee	5.8
Peace River	6.8
Garden City	6.7
Other	1.4
Total	$ 43.2

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.

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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 (adjusted for unrealized (gains) losses on derivative contracts and borrowing availability) 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 September 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 determined semi-annually and may be determined at other times upon request by the lenders under certain circumstances. Determinations are based upon a number of factors, including estimated future natural gas prices and estimated future production levels. On October 6, 2008, the lenders reaffirmed the Company s borrowing base of $180 million after completing its mid-year borrowing base determination. The next regular borrowing base determination, which will be based on the December 31, 2008 reserve report as prepared by the Company s independent reserve engineers, is scheduled to be complete on or before June 30, 2009. Upon a determination, 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 September 30, 2008, we had $108 million outstanding under our revolving credit facility. For the nine months ended September 30, 2008, interest on the borrowings averaged 4.81% per annum. Borrowing availability at September 30, 2008 was $72 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 December 2007, the Financial Accounting Standards Board (the FASB) issued Statement of Financial Accounting Standards No. 141R, Business Combinations (Revised 2007) (SFAS 141R), which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. We will evaluate the impact of SFAS No. 141R on our consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

In September 2006, the FASB issued SFAS 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

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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. We have elected to defer the application of SFAS 157 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 October 10, 2008, the FASB issued Staff Position No. FAS 157-3 (FSP No. 157-3). FSP No. 157-3 clarifies the application of SFAS 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. On January 1, 2009, we will adopt SFAS 157 as it relates to nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. We do not expect any significant impact to our consolidated financial statements when we implement SFAS 157 for our existing non-financial assets and liabilities.

On February 15, 2007, the FASB issued SFAS 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 December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements (SFAS 160). SFAS 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires that changes in a parent s ownership interest in a subsidiary be reported as an equity transaction in the consolidated financial statements when it does not result in a change in control of the subsidiary. When a change in a parent s ownership interest results in deconsolidation, a gain or loss should be recognized in the consolidated financial statements. SFAS 160 must be applied prospectively as of January 1, 2009, except for the presentation and disclosure requirements, which are required to be applied retrospectively for all periods presented. The adoption of SFAS 160 will not have a material impact on our results of operations, cash flows or financial positions; however, it could impact future transactions entered into by us.

In March 2008, the FASB issued SFAS 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.

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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 September 30, 2008, a 10% decrease in the prices received for natural gas production would have had an approximate $2.7 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 September 30, 2008, we had $108 million outstanding under our revolving credit facility. For the nine months ended September 30, 2008, interest on the borrowings averaged 4.81% per annum. Borrowing availability at September 30, 2008 was $72 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 September 30, 2008, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.7 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 September 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

Buchanan County Dispute. On September 12, 2008, the Virginia Supreme Court issued its decision in this matter in favor of us and PMC, reversing and remanding the matter to the Buchanan Circuit Court for further action consistent with the decision. The Court held that CNX Gas Company LLC (CNX) does not have the exclusive right to transport gas across the Pocahontas Mining Limited Liability Company (PMC) property and may not prevent uses of the PMC property that do not conflict with the exercise of CNX s rights under its lease. The effect of this ruling is that our pipeline right of way with PMC is valid.

This dispute began during the construction of our 12-mile Pond Creek gathering line, a portion of which traverses a right-of-way granted to us by 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, the lessee of certain minerals underlying the

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PMC property, had claimed that it had 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 September 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. Oral argument before the Virginia Supreme Court was held on June 2, 2008.

Tazewell County Dispute**.** 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 in Tazewell County.

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 September 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 the following 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:

Natural gas prices are volatile, and a decline primarily in natural gas prices would significantly affect our financial results and impede our growth.

Our revenue, profitability, and cash flow depend upon the prices and demand for natural gas. The market for natural gas is very volatile and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas;
- the price of foreign imports;
- overall domestic and global economic conditions;
- the consumption pattern of industrial consumers, electricity generators, and residential users;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Many of these factors are beyond our control. Because all of our estimated proved reserves as of December 31, 2007 were natural gas reserves, our financial results are sensitive to movements in natural gas prices. Recent natural gas prices have been extremely volatile and we expect this volatility to continue. For example, from January 1, 2008 to October 31, 2008, the NYMEX natural gas spot price ranged from a high of $13.54 per MMBtu to a low of $6.12 per MMBtu.

The results of higher investment in the exploration for and production of gas and oil and other factors, such as global economic and financial conditions discussed below, may cause the price of gas to fall. Lower natural gas prices may not only decrease our revenues on a per Mcf basis, but also may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition, results of operations and cash flow. If there are substantial downward adjustments to our estimated proved reserves or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carry amount may not be recoverable or whenever management s plans change with respect to those assets. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

If natural gas prices decline significantly for an extended period of time, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on acceptable terms, all of which can affect the value of our common stock.

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

None.

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.

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SIGNATURES

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

GeoMet, Inc.

Date: November 7, 2008	By /s/ William C. Rankin William C. Rankin, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS

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

* Attached hereto