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 June 30, 2007

OR

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

For the transition period from ______ to ______

Commission File Number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

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

N/A

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

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

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

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x

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

As of August 1, 2007 there were 38,873,454 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)

	June 30, 2007	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,837,721	$ 1,414,476
Accounts receivable	8,546,391	10,881,479
Current portion of notes receivable	85,151	81,181
Derivative asset	2,681,578	4,290,599
Other current assets	191,581	648,053
Total current assets	14,342,422	17,315,788
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	342,976,546	310,011,154
Unevaluated gas properties, not subject to amortization	25,183,826	26,397,982
Other property and equipment	2,499,633	2,314,190
Total property and equipment	370,660,005	338,723,326
Less accumulated depreciation, depletion, and amortization	(27,242,634)	(22,849,903)
Property and equipment net	343,417,371	315,873,423
Other noncurrent assets:		
Note receivable	285,530	298,936
Derivative asset		1,043,108
Other	669,976	663,511
Total other noncurrent assets	955,506	2,005,555
TOTAL ASSETS	$ 358,715,299	$ 335,194,766
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 11,278,439	$ 14,284,921
Accrued liabilities	3,478,814	2,917,575
Deferred income taxes	944,838	1,570,684
Asset retirement liability	77,837	73,047
Current portion of long-term debt	61,512	94,177
Total current liabilities	15,841,440	18,940,404
Long-term debt	81,300,510	60,832,110
Asset retirement liability	2,735,564	2,480,754

Other long-term accrued liabilities	154,762	154,455
Derivative liability	61,100	
Deferred income taxes	44,896,412	42,779,537
TOTAL LIABILITIES	144,989,788	125,187,260
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 38,873,454 and 38,678,713 at June 30, 2007 and December 31, 2006, respectively	38,873	38,679
Paid-in capital	187,181,828	186,852,852
Accumulated other comprehensive income (loss)	1,172,172	(193,888)
Retained earnings	25,712,921	23,740,144
Less notes receivable	(380,283)	(430,281)
TOTAL STOCKHOLDERS EQUITY	213,725,511	210,007,506
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 358,715,299	$ 335,194,766

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income

(Unaudited)

	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Revenues:				
Gas sales	$ 13,438,859	$ 10,139,536	$ 25,287,061	$ 22,450,945
Gas marketing	8,901,311		17,443,797	
Operating fees and other	324,247		616,000	
Total revenues	22,664,417	10,139,536	43,346,858	22,450,945
Expenses:				
Purchased gas	8,795,737		17,228,056	
Lease operating expense	3,424,409	2,832,789	6,793,644	5,673,653
Compression and transportation expense	1,355,148	1,055,148	2,867,566	2,131,638
Production taxes	317,368	236,193	597,681	504,937
Depreciation, depletion and amortization	2,265,451	1,746,481	4,340,774	3,580,486
Research and development		29,137		98,392
General and administrative	2,227,424	1,436,024	4,503,688	2,455,580
Realized (gains) losses on derivative contracts	(50,404)	(439,368)	(1,296,530)	156,204
Unrealized (gains) losses on derivative contracts	(1,860,987)	(1,371,124)	2,713,229	(10,444,656)
Total operating expenses	16,474,146	5,525,280	37,748,108	4,156,234
Income from operations	6,190,271	4,614,256	5,598,750	18,294,711
Other income (expense):				
Interest income	18,124	7,319	25,097	18,213
Interest expense (net of amounts capitalized)	(1,260,412)	(765,765)	(2,135,417)	(1,629,139)
Other	4,045	31,645	(24,623)	18,268
Total other income (expense)	(1,238,243)	(726,801))	(2,134,943)	(1,592,658)
Income before income taxes	4,952,028	3,887,455	3,463,807	16,702,053
Income tax expense	1,953,387	1,596,236	1,491,029	7,247,736
Net income	$ 2,998,641	$ 2,291,219	$ 1,972,778	$ 9,454,317
Other comprehensive income, net of income taxes				
Foreign currency translation adjustment, net of income tax of $0	1,460,022	264,703	1,366,060	239,653
Comprehensive Income	$ 4,458,663	$ 2,555,922	$ 3,338,838	$ 9,693,970
Net income per common share:				
Basic	$ 0.08	$ 0.07	$ 0.05	$ 0.29
Diluted	$ 0.08	$ 0.07	$ 0.05	$ 0.28

Weighted average number of common shares:				
Basic	38,710,319	32,711,133	38,704,051	32,212,497
Diluted	39,400,890	33,702,095	39,385,935	33,296,767

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2007	2006
Cash flows provided by operating activities:		
Net income	$ 1,972,778	$ 9,454,317
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	4,427,660	3,350,182
Amortization of debt issuance costs	69,922	64,556
Deferred income taxes	1,491,029	7,492,460
Unrealized losses (gains) from the change in market value of open derivative contracts	2,713,229	(10,444,656)
Stock-based compensation	163,024	197,672
Gain on sale of assets	(15,954)	(19,689)
Accretion expense	103,036	75,665
Changes in operating assets and liabilities:		
Accounts receivable	2,379,534	1,763,501
Other current assets	456,473	120,722
Accounts payable	(3,503,299)	4,354,216
Other accrued liabilities	561,546	85,913
Net cash provided by operating activities	10,818,978	16,494,859
Cash flows used in investing activities:		
Capital expenditures	(29,951,279)	(34,569,868)
Proceeds from sale of other property and equipment	22,159	112,026
Collection of notes receivable	9,435	297,942
Other assets	(76,003)	(348,426)
Net cash used in investing activities	(29,995,688)	(34,508,326)
Cash flows provided by financing activities:		
Debt issuance costs		(262,644)
Treasury stock	(4,382)	
Proceeds from exercise of stock options	140,696	858,469
Equity offering costs		(1,309,862)
Proceeds from sales of common stock		28,012,809
Credit facility borrowings	20,500,000	41,750,000
Proceeds from notes receivable and accrued interest		17,184,357
Payments on other debt	(64,264)	(67,809,110)
Net cash provided by financing activities	20,572,050	18,424,019
Effect of exchange rate changes on cash	27,905	(43,394)
Increase in cash and cash equivalents	1,423,245	367,158
Cash and cash equivalents at beginning of period	1,414,476	615,806
Cash and cash equivalents at end of period	$ 2,837,721	$ 982,964

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) (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 involved in the exploration, development and production of natural gas from coal seams (coal bed methane). Our principal operations and producing properties are located in Alabama, West Virginia, and Virginia. We operate in two segments, natural gas exploration, development and production, exclusively within the continental United States and British Columbia and gas marketing in the United States.

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 financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for year-end 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 financial statements for the fiscal year ended December 31, 2006 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 20, 2007.

On January 1, 2007, we exercised our purchase option and acquired 100% of Shamrock Energy LLC, our gas marketing subsidiary. In return, we provided Jon M. Gipson, the former owner of Shamrock, an at-will employment position with us. Also, pursuant to the terms of our purchase option, on March 9, 2007, we caused Shamrock to distribute to Mr. Gipson approximately $22,500, which equals 50% of the net profits generated by Shamrock from August 1, 2006 through January 1, 2007. This amount was accrued at December 31, 2006 as a dividend payable to Mr. Gipson. No additional consideration was paid as a result of our exercise of this purchase option. Over 99% of the net assets acquired were current, approximated their fair value and were equal to zero. Shamrock Energy LLC is a low margin business and as a result it does 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.

Note 2 Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation Number (FIN) 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. This interpretation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified $269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48. For additional information see Note 12.

In September 2006, the FASB issued FASB Statement No. 157, *Fair Value Measurements* (FASB 157). FASB 157 establishes a single authoritative definition of fair values sets out a framework for measuring fair values and requires additional disclosures about fair value measurements. FASB 157 applies only to fair value measurements that are already required or permitted by other accounting standards. FASB 157 is effective for fiscal years beginning after November 15, 2007. We do not expect FASB 157 to have a material impact on our consolidated financial position or results of operations upon adoption.

On February 15, 2007, the FASB issued FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB 115, (FASB 159). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of FASB 159 are elective;

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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 FASB 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. FASB 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity (i) makes that choice in the first 120 days of that year, (ii) has not yet issued financial statements for any interim period of such year, and (iii) elects to apply the provisions of FASB 157, Fair Value Measurements. Management is currently evaluating the impact of FASB 159, if any, on our financial statements.

Note 3 Net Income Per Share

Net Income 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. No dilution for any potentially dilutive securities is included. 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		Six Months Ended	
		June 30,		
	2007	2006	2007	2006
Net income per share:				
Basic-net income per share	$ 0.08	$ 0.07	$ 0.05	$ 0.29
Diluted-net income per share	$ 0.08	$ 0.07	$ 0.05	$ 0.28
Numerator				
Net income available to common stockholders basic	$ 2,998,641	$ 2,291,219	$ 1,972,778	$ 9,454,317
Denominator:				
Weighted average shares outstanding-basic	38,710,319	32,711,133	38,704,051	32,212,497
Add potentially dilutive securities:				
Stock options and restricted stock	690,571	990,962	681,884	1,084,270
Weighted average shares and potential dilutive shares outstanding	39,400,890	33,702,095	39,385,935	33,296,767

Note 4 Gas Properties

We use the full cost method of accounting for our investment in gas properties. Under this method of accounting, all costs of acquisition, exploration and development of gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs related to unsuccessful projects, tangible and intangible development costs) are included in the full cost pool. In addition, we capitalize interest expense, and direct general and administrative expenses. Also under full cost accounting rules, total net 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 test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation using natural gas prices in effect as of the balance sheet date as adjusted for basis or location differential, held constant over the life of the reserves. To the extent that capitalized costs of gas properties, net of accumulated depreciation, depletion and amortization and income taxes, exceed the ceiling limitation, such excess capitalized costs would be charged to results of operations. During the six months ended June 30, 2007 there were no charges to results of operations due to the ceiling limitation. We also perform a quarterly impairment test on our unevaluated properties. During the six months ended June 30, 2007, we recorded an impairment of $4.2 million related to certain prospects located in North Central Louisiana and such impairment was added to our full cost pool.

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 six months ended June 30, 2007:

Asset retirement obligation at beginning of year	$ 2,553,801
Liabilities incurred	124,068
Liabilities settled	
Accretion	118,272
Revisions in estimates	(19)
Foreign currency translation	17,279
Asset retirement obligation at end of period	2,813 401
Less: current portion of obligation	77,837
Long-term asset retirement obligation	$ 2,735,564

Note 6 Price Risk Management Activities

We engage in price risk management activities from time to time. These activities are designed to manage our exposure to fluctuations in the price of natural gas. We utilize derivative financial instruments, primarily three-way collars, traditional collars and swaps, as the means to manage this price risk. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty the difference between the index price and the ceiling price. If the index price falls below the floor price, the counterparty pays us the difference between the index price and the floor price.

We account for our derivative contracts as accounting hedges using mark-to-market accounting under FASB 133, *Accounting for Derivative Instruments and Hedging Activities.* During the three and six months ended June 30, 2007, we recognized gains of $1.9 million and losses of $1.4 million including realized gains of $50,404 and $1.3 million, respectively. During the three and six months ended June 30, 2006, we recognized gains on derivative contracts of $1.8 million and $10.3 million including realized gains of $439,368 and losses of $156,204, respectively.

At June 30, 2007 and at December 31, 2006, the fair values of open net derivative contracts assets were approximately $2.6 and $5.3 million, respectively.

As of June 30, 2007, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units. For our natural gas derivative contracts, summer months apply to April through October and winter months apply to November through March.

			Collars	
		Volumes	Weighted Average Floor Prices	Weighted Average Cap Prices
Instrument Type	**Production Period**	**(MMBtu)**	**($/MMBtu)**	**($/MMBtu)**
Collars (3 way)	July-October 2007	984,000	$ 5.75-$7.38	$ 10.50
Collars (3 way)	Winter 2007/2008	1,216,000	$ 6.00-$9.00	$ 14.80
Collars (3 way)	Summer 2008	1,712,000	$ 5.00-$7.00	$ 10.50
Traditional Collars	July-October 2007	492,000	$ 7.50	$ 9.75
Traditional Collars	Winter 2007/2008	608,000	$ 8.25	$ 11.25

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Note 7 Long-Term Debt

The following is a summary of our long-term debt at June 30, 2007 and December 31, 2006:

	June 30, 2007	December 31, 2006
Borrowings under bank credit facility	$ 80,500,000	$ 60,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	174,570	210,227
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	133,820	138,308
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	553,632	577,752
Total debt	81,362,022	60,926,287
Less current maturities included in current liabilities	(61,512)	(94,177)
Total long-term debt	$ 81,300,510	$ 60,832,110

We initially entered into a bank credit facility in December 2001. In January 2006, we amended and restated the bank credit facility and, among other things, extended the maturity date to January 6, 2011. In June 2006, the revolving credit facility was amended and restated and increased to $180 million and the borrowing base was increased to $150 million. Pursuant to the amended credit agreement, we have a $180 million revolving credit facility that permits us to borrow amounts from time to time based on the available borrowing base as determined in the credit agreement. The bank credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the bank credit facility is based upon the valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of June 30, 2007, we had $80.5 million of borrowings outstanding under our credit facility, resulting in a borrowing availability of $69.5 million under our $150 million borrowing base. For the six months ended June 30, 2007 we borrowed $44.5 million and made payments of $24 million under the credit facility. As of June 30, 2007 the outstanding balances on the revolving credit facility bear interest at either the bank s adjusted base rate, which is the bank s base rate of at least the Federal Funds Rate plus 0.5%, or the adjusted LIBOR rate, plus a margin of 1.00% to 2.00%, based on borrowing base usage.

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio of 1.0 to 1.0, and a maximum rate of EBITDA to interest expense of 2.75 to 1.0, both as defined in the credit agreement. As of June 30, 2007, we were in compliance with all of the covenants in the credit agreement.

Note 8 Common Stock

Effective January 24, 2006, our board of directors approved a four-for-one common stock split and increased our authorized capital stock from 40,000,000 shares of common stock to 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock and 10,000,000 shares of preferred stock. Prior periods have been adjusted for the stock split.

On January 30, 2006 and February 7, 2006, we completed private equity offerings of an aggregate 10,250,000 shares of our common stock, consisting of 2,317,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers exempt from registration under the Securities Act. We received aggregate consideration of approximately $28.0 million, or $12.09 per share. We did not receive any proceeds from the shares sold by certain of our existing stockholders. In addition, we received approximately $17.5 million from certain of the selling stockholders for repayment of loans from us, including accrued and unpaid interest thereon. We used the net proceeds from this private equity offering, together with the proceeds from the repayment of certain of the selling stockholders loans, to repay a portion of the borrowings under our bank credit facility and for general corporate purposes.

On July 27, 2006, we registered for re-sale with the SEC the 10,250,000 shares of common stock issued in the private equity offering discussed above. Also on July 27, 2006, we sold 5,750,000 shares of our common stock under an underwritten initial public offering. Our initial public offering closed on August 2, 2006, and the price per share was $10.00. We received net proceeds of approximately $52.6 million from our initial public offering, after deducting estimated offering expenses and underwriting discounts and commissions. We used the net proceeds from the initial public offering to reduce outstanding borrowings under our bank credit facility.

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For the six months ended June 30, 2007, we issued a total of 37,305 shares of common stock upon the exercise of stock options and 157,436 shares of restricted stock.

Note 9 Share-Based Awards

Prior to January 1, 2006, stock-based employee compensation was accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25, *Accounting for Stock Issued to Employees* (APB 25). The exercise price of the options granted was equal to the estimated market value of our common stock at grant date, and therefore, no compensation costs have been recognized. We used the income method on a semi-annual basis to estimate the market value of our common stock at grant date.

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

As of June 30, 2007, 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 the 2006 Long-Term Incentive Plan, but we will continue to issue shares of our common stock upon exercise of awards that were 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. The maximum number of shares available for grant under this plan is 2,000,000. 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 interest of our employees and directors interests with the interests of our stockholders, and to closely link compensation with our performance. Generally, the exercise price of a stock option 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, vest evenly over three years, except for awards that are performance based and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criterion has been met. Options issued to our directors vest immediately.

In March 2007, we granted 168,975 share-based stock option awards and in June 2007 we granted 138,000 restricted stock awards to certain of our non-executive employees with time vesting criteria. During the six months ended June 30, 2007, we recorded a compensation accrual of $242,853, which was allocated among general and administrative expenses ($152,808), lease operating expenses ($10,216), and gas properties ($79,829). The future compensation cost of all the outstanding awards is $1,945,607 and will be amortized over the vesting period of such stock options and restricted stock. Our four executive officers and two other officers did not receive any of these awards.

In April and May 2006, we granted 224,810 share-based stock option awards to certain of our employees, our executives and our independent directors. Also in April 2006, we granted 12,249 performance based restricted stock awards to our executives.

During the six months ended June 30, 2006, we recorded a compensation expense accrual of $326,224, which was allocated among lease operating expenses ($105,003), general and administrative expenses ($92,669), domestic full cost pool ($119,029) and capitalized to unevaluated gas properties ($9,523).

Significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 38.05%, risk-free interest rate of 4.43%, an expected term of 4.5 years, and a forfeiture rate of 1.5%. The forfeiture rate was changed to 10% for the second quarter.

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Incentive Stock Options

The table below summarizes incentive stock option activity for the six months ended June 30, 2007:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2006	572,838	$ 6.32	4.26	
Granted	168,975	$ 8.30	6.50	
Forfeited	20,078	$ 10.03		
Exercised	37,305	$ 3.77		
Outstanding at June 30, 2007	684,430	$ 6.84	4.44	$ 1,487,244
Options exercisable at June 30, 2007	377,965	$ 4.44	2.98	$ 1,486,649

The total intrinsic value (market price less option price) of the incentive stock options exercised during the six months ended June 30, 2007 was $193,640, and we received $140,696 in cash from the exercise of the incentive qualified stock options. The total intrinsic value (market price less option price) of incentive stock options exercised during the six months ended June 30, 2006 was $3.8 million, and we received $0.4 million in cash.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the six months ended June 30, 2007:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2006	1,113,865	$ 3.20	6.15	
Granted				
Forfeited				
Exercised		$		
Outstanding at June 30, 2007	1,113,865	$ 3.20	5.65	$ 5,366,400
Options exercisable at June 30, 2007	1,048,000	$ 2.60	5.66	$ 5,366,400

No non-qualified stock options were exercised or granted during the six months ended June 30, 2007. The total intrinsic value (current market price less option strike price) of non-qualified stock options exercised during the six months ended June 30, 2006 was $1.7 million, and we received $0.4 million in cash.

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Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2007:

	Non-Vested Restricted Stock Awards
Non-vested restricted stock at December 31, 2006	21,436
Granted	138,000
Forfeited	2,000
Vested	
Non-vested restricted stock at June 30, 2007	157,436

In June 2007, we granted 138,000 restricted stock awards to non-executive employees. The restricted stock awards are subject to performance-based vesting for our executive officers and two other officers and time-based vesting for non-executive employees. The restricted stock awards will vest as a result of a triggering event such as a corporate change of control or merger. The fair value of the restricted stock awards at June 30, 2007 is approximately $1,205,959. In April 2006, we granted 12,249 performance based restricted stock awards to our executive officers and two other officers.

Note 10 Commitments and Contingencies

Litigation From time to time, we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, our results of operations or cash flows, if any, will be material except for the litigation discussed below. As of June 30, 2007, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability.

CNX Surface Use Dispute

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

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through the Pond Creek gathering line. On July 30, 2007, we filed our petition for appeal of the portion of the order which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007 CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the tract. 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. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we will be required to seek alternative ways to transport our gas to market. Even assuming such alternatives are available, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company, an affiliate of CNX (Island Creek), in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking 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 seeks $561 million for 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 alleges CNX s intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX s position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

El Paso Overriding Royalty Interest Dispute

We filed a claim in the 116th District Court of Dallas County, Texas on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in the White Oak Creek field in Alabama. We had previously entered into an agreement to sell our interests in the field to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests, and that we are entitled to retain all overriding royalty interests we own in the field. The trial court rendered judgment in our favor, and El Paso appealed the decision of the trial court. The appellate court reversed the trial court s decision in favor of El Paso and remanded the case to the trial court to determine whether El Paso is entitled to specific performance and damages (lost royalties). On August 3, 2007, our petition for a rehearing with the appellate court was denied. We are considering additional options including further appeals. To date, El Paso has not paid us the allocated purchase price for the overriding royalties of approximately $10.5 million. We have received royalty payments from the disputed overriding royalty interests of approximately $9.2 million since April 2004. We do not expect the outcome of this dispute to have a material economic effect on our operations, as the economic value of the override is not materially different from its purchase price.

Note 11 Segment Information

We are engaged in the exploration, development and production of natural gas from coal seams (coal bed methane) primarily in the United States and Canada. Our acquisition of Shamrock Energy LLC on January 1, 2007 (see Note 1) created a gas marketing activity that added a second reportable segment to our core business of natural gas exploration, development and production. Prior to January 1, 2007, we consolidated Shamrock Energy LLC as a variable interest entity under FIN 46 (R) from August 1, 2006 to December 31, 2006. From January 1, 2006 through July 31, 2006, we sold substantially all of our gas production to Shamrock Energy LLC as a third party customer.

Using guidelines set forth in FASB Statement No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have identified two reportable segments; (i) exploration, development and production of natural gas and (ii) marketing natural gas.

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Information concerning our business activities is summarized as follows:

	Natural Gas Exploration & Production	Marketing Natural Gas	Eliminations	Total
As of and for the three months ended June 30, 2007:				
Revenues from external customers	$ 13,763,106	$ 8,901,311	$	$ 22,664,417
Intersegment revenues	$ 13,147,106	$	$ (13,147,106)	$
Operating income (loss)	$ 6,203,472	$ (13,201)	$	$ 6,190,271
Total assets	$ 355,416,811	$ 9,008,229	$ (5,709,741)	$ 358,715,299

	Natural Gas Exploration & Production	Marketing Natural Gas	Eliminations	Total
As of and for the six months ended June 30, 2007:				
Revenues from external customers	$ 25,903,061	$ 17,443,797	$	$ 43,346,858
Intersegment revenues	$ 25,287,061	$	$ (25,287,061)	$
Operating income (loss)	$ 5,633,235	$ (34,485)	$	$ 5,598,750
Total assets	$ 355,416,811	$ 9,008,229	$ (5,709,741)	$ 358,715,299

All sales and primarily all operating income occurred in the United States. For the three and six months ended June 30, 2007, natural gas exploration and production cash capital expenditures were $27,993,685 in the United States and $1,957,594 in Canada. Marketing natural gas is not capital intensive and there were no capital expenditures related thereto for the three and six months ended June 30, 2007. We sell substantially all of our gas production to our natural gas marketing segment, Shamrock Energy LLC.

Note 12 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the FASB Statement No. 109, *Accounting for Income Taxes*. This results in the recognition of deferred tax assets and liabilities using estimated effective tax rates for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities using enacted tax rates at the end of the period. Under FASB No. 109, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net operating losses under Section 382 of the Internal Revenue Code. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use the NOLs in the United States to offset current tax liabilities in future years.

Our effective tax rate differs from the federal statutory rate primarily due to losses in Canada that we are unable to benefit from and state income taxes. The Canadian losses are fully reserved because it is more likely than not that we will not use those NOLs to offset current tax liabilities in future years.

Uncertain Tax Positions

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified $269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48 principally due to the size of our NOLs. The amount of unrecognized tax benefits did not materially change as of June 30, 2007.

As of January 1, 2007, we had $269,900 of unrecognized tax benefits. If recognized, the amount that would impact income tax expense is immaterial to the financial statements. There have been no significant changes to these amounts during the three and six months ended June 30, 2007.

It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or the financial position.

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We file a consolidated federal income tax return in the United States and various combined and separate filings in Canada, and several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2002.

Our continuing practice is to recognize estimated interest related to potential underpayment on any unrecognized tax benefits as a component of interest expense in the consolidated statement of operations. Penalties, if incurred, would be recognized as a component of penalty expense. As of the date of adoption of FIN 48, we did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the quarter.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to June 30, 2008.

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

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

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2006, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 20, 2007.

Overview

We are an independent natural gas producer involved in the exploration, development, and production of natural gas from coal seams (coalbed methane). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. As of June 30, 2007, we control a total of approximately 296,000 net acres of coalbed methane and oil and gas development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We operate in two segments, (i) natural gas exploration, development and production, exclusively within the continental United States and British Columbia, Canada and (ii) natural gas marketing in the United States.

Our focus is in developing the two primary producing fields that we own and operate, the Gurnee field located in the Cahaba Basin and the Pond Creek field located in the central Appalachian Basin. In addition, we are conducting exploration and evaluation activities in Alabama, West Virginia and British Columbia.

Our financial results are impacted by many factors such as the price of natural gas, our levels of production, and our ability to market our production. Commodity prices and production volumes are affected by changes in market demand, which is impacted by overall economic activity, weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas prices and levels of production, and, therefore, we cannot determine what effect increases or decreases will have on our capital program, future revenues and reserves. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas reserves at economical costs are critical to our long-term success.

For the three and six months ended June 30, 2007, gas sales quantities increased by 272 MMcf and 622 MMcf from the comparable prior period to 1.8 Bcf and 3.5 Bcf, respectively. The increase in sales was related to the continued development of our Gurnee and Pond Creek fields. Average gas sales prices for the three and six months ended June 30, 2007 increased by $0.82 and decreased by $0.33 per Mcf from the comparable prior period to $7.63 per Mcf and $7.56 per Mcf, respectively.

To reduce our exposure to fluctuations in natural gas prices, which have exhibited a high degree of volatility over the past several years, we periodically enter into derivative commodity instruments. Currently, we use collars as our mechanism for hedging commodity prices. We account for our derivative instruments on a mark-to-market basis, and changes in the fair

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value of derivative instruments are recognized as gains and losses which are included in operating expense in the period of change. While we believe that the stabilization of prices and protection afforded us by providing a revenue floor for our sales is beneficial, this strategy may result in lower revenues than we would have if we were not a party to derivative instruments in times of rising natural gas prices. Our policy is to enter into hedging transactions that increase our probability of achieving our targeted level of cash flows. As a result of these hedging positions, during the three and six months ended June 30, 2007, we recognized gains of $1.9 million and losses of $1.4 million including realized gains of $50,404 and $1.3 million, respectively. During the three and six months ended June 30, 2006, we recognized gains on derivative contracts of $1.8 million and $10.3 million including realized gains of $439,368 and losses of $156,204.

We believe that our cash flow from operations and other financial resources such as borrowings under our credit facility, and proceeds from future equity offerings will provide us with the ability to develop our existing properties and finance our current exploration on unevaluated properties.

Recent Developments

Gurnee Field

Our production at the Gurnee field in 2007 is not inclining at this point as we would expect from a CBM field, resulting in essentially flat production over the last four quarters.

Several factors have resulted in delays in initial production or in the dewatering process thereby contributing to this performance. These factors included right-of-way delays that deferred production on 19 wells, initial high water production with little gas production from those 19 wells once online and electrical outages that have reduced certain wells pumping times, which delay the dewatering of the coals. In general, Gurnee field has not yet performed in the manner we expected earlier. Currently, only approximately 10% of the producing wells in the field exhibit an inclining production profile; a similar number of wells currently have a declining production profile, although we expect such declines to be generally arrested over time. The remaining wells in the field have a flat production profile.

The characteristics of coalbed methane basins differ and other basins have experienced similar production difficulties in the early stages of their development. In fact, we encountered similar production performance issues in our Pond Creek field and we ultimately devised well treatment techniques to deal with the unique characteristics of that field.

The well treatment techniques which have been successful in the Pond Creek field have not resulted in success in the Gurnee field. We have had encouraging results with a new well treatment technique that we recently applied to several wells in the field. It is too early to determine if this new technique will have long-term benefits or have broad application across the field. Ultimately, multiple techniques may be required and will likely result in additional expense.

We do not believe that the current well performance in the Gurnee field will result in a material decline in the quantities of proved reserves for the field. Based upon this current performance, current estimates indicate that the recovery of the proved reserves will be extended over a longer period of time. As a result, future cash flows may be delayed, operating costs may be higher and the rate of return on our investment in these wells may be reduced. We continue to believe that we will ultimately be successful in improving the production performance in the Gurnee field as we have been in three other coalbed methane basins in the United States.

We have decided to further reduce our drilling in Gurnee from the planned 52 wells to 26 wells to reallocate capital to fund a well treatment program in the Gurnee field, the drilling of several exploratory wells and expenditures in the projects discussed below.

Lasher Project

In our Lasher prospect which lies about 10 miles north of Pond Creek in Wyoming County, West Virginia, we own approximately 16,548 undeveloped leasehold acres. We now have available firm capacity on the Columbia KA-20 line which transverses the project making the project viable. We have begun the process to obtain a tie-in to the Columbia line. As a result, we intend to move forward with development and drill several wells in the last half of the year. We believe we can drill approximately 130 CBM wells on the project and estimate net recoverable resource of approximately 50 Bcf. The wells are estimated to cost about $425,000 each including allocated facility costs. We hope to be selling gas in the near future.

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Peace River Project

We have begun the necessary steps to drill up to 25 wells in the Peace River project which consists of approximately 44,468 gross acres (22,334 acres, net to our 50% working interest) in the Peace River area near Hudson s Hope, British Columbia.

Our next step will be to begin consultations with affected communities and First Nations (Canadian indigenous populations). We have begun the design of the initial drilling plan which will include at least one produced water disposal well and the necessary project infrastructure and gas treating and sales facilities. After finalizing permitting and receiving approval by our Board of Directors we will initiate construction of drilling locations and infrastructure.

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 significant changes to our critical accounting policies during the six months ended June 30, 2007.

Natural Gas Production Producing Fields Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the three and six months ended June 30, 2007 and 2006. This table should be read with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended		Six Months Ended	
	June 30,			
	2007	2006	2007	2006
Gas sales	$ 13,439	$ 10,140	$ 25,287	$ 22,451
Lease operating expenses	$ 3,425	$ 2,833	$ 6,794	$ 5,674
Compression and transportation expenses	1,355	1,055	2,867	2,132
Production taxes	317	236	598	505
Total production expenses	$ 5,097	$ 4,124	$ 10,259	$ 8,311
Net sales volumes (MMcf)	1,761	1,489	3,467	2,845
Pond Creek field	1,110	913	2,176	1,783
Gurnee field	548	467	1,088	839
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 7.63	$ 6.81	$ 7.29	$ 7.89
Average natural gas sales price realized(1)	$ 7.66	$ 7.10	$ 7.67	$ 7.84
Lease operating expenses	$ 1.94	$ 1.90	$ 1.96	$ 1.99
Pond Creek field	$ 1.72	$ 1.44	$ 1.70	$ 1.51
Gurnee field	$ 2.75	$ 3.26	$ 2.84	$ 3.55
Compression and transportation expenses	$ 0.77	$ 0.71	$ 0.83	$ 0.75
Pond Creek field	$ 1.01	$ 0.96	$ 1.09	$ 1.00
Gurnee field	$ 0.40	$ 0.37	$ 0.43	$ 0.42
Production taxes	$ 0.18	$ 0.16	$ 0.17	$ 0.18
Pond Creek field	$ 0.01	$ 0.02	$ 0.02	$ 0.02
Gurnee field	$ 0.47	$ 0.38	$ 0.44	$ 0.44
Total production expenses	$ 2.89	$ 2.77	$ 2.96	$ 2.92
Pond Creek field	$ 2.74	$ 2.42	$ 2.81	$ 2.53

Gurnee field	$ 3.62	$ 4.01	$ 3.71	$ 4.41
Depreciation, depletion and amortization	$ 1.29	$ 1.17	$ 1.25	$ 1.26

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

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Results of Operations Natural Gas Production

Three Months Ended June 30, 2007 compared with Three Months Ended June 30, 2006

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006 (In thousands)	Change
Gas sales	$ 13,439	$ 10,140	33%
Operating fees and other	324		100%
Total revenues	$ 13,763	$ 10,140	36%
Lease operating expenses	$ 3,425	$ 2,833	(21)%
Compression and transportation expenses	1,355	1,055	(28)%
Production taxes	317	236	(34)%
Depreciation, depletion and amortization	2,265	1,746	(30)%
Research and development		29	NM
General and administrative	2,108	1,436	(47)%
Realized losses (gains) on derivative contracts	(50)	(439)	NM
Unrealized (gains) from the change in market value of open derivative contracts	(1,861)	(1,371)	NM
Total operating expenses	$ 7,559	$ 5,525	NM
Income (loss) from natural gas production	$ 6,204	$ 4,615	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $3.3 million, or 33%, to $13.4 million compared to the prior year quarter. The increase in gas sales was primarily a result of increased average sales prices and increased production. Production increased 18% while average gas prices increased 12%, excluding hedging transactions. The $3.3 million increase in gas sales consisted of a $1.4 million increase in prices and a $1.9 million increase in production. The increase in production was principally attributable to the continued development activities at our Gurnee and Pond Creek fields.

Lease operating expenses. Lease operating expenses increased by $0.592 million, or 21%, to $3.4 million. The increase in lease operating expenses consisted of $0.518 million increase in production and $0.074 million increase in costs.

Compression and transportation expenses. Compression and transportation expenses increased by $0.300 million, or 28%, to $1.4 million. The increase in compression and transportation expenses consisted of a $0.193 million increase in production and a $0.107 million increase in costs. The increase in costs is related to increase in transportation costs at our Pond Creek field compared to the prior year quarter.

Production taxes. Production taxes increased by $0.081 million, or 34%, to $0.317 million. The increase in production taxes consisted of a $0.43 million increase in production and $0.038 million increase in average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.519 million, or 30%, to $2.3 million. The depreciation, depletion and amortization increase consisted of a $0.319 million increase in production and $0.200 million increase in the depletion rate. The increase in the rate is due to increased future development costs and higher cost of drilling.

General and administrative. General and administrative expenses increased by $0.672 million or, 47%, to $2.1 million. The primary drivers for the increased general and administrative expenses were professional services and employee expenses. Professional services consisted of increased audit fees, Sarbanes-Oxley compliance costs, tax services and legal services. Employee expenses increased as a result of increased personnel and higher costs of salary and wages.

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Realized losses (gains) on derivative contracts. Realized gains on derivative contracts decreased by $0.389 million to $0.050 compared to a $0.439 million in the prior year quarter. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized gains from the change in market value of open derivative contracts resulted in a $1.9 million gain as compared to a $1.4 million gain in the prior year quarter. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair values of derivative liabilities increase. The $1.9 million gain was a result of decreased future commodity gas prices.

Results of Operations Marketing Natural Gas

Three Ended Months June 30, 2007 compared with Three Months Ended June 30, 2006

The acquisition of Shamrock Energy LLC on January 1, 2007 (see Note 1 of the unaudited consolidated financial statements) added a second reportable segment, natural gas marketing, to our core business of natural gas exploration, development and production. This entity was previously consolidated as a variable entity from August 1 through December 31, 2006. From January 1, 2006 through July 31, 2006, we sold substantially all of our gas production to Shamrock Energy LLC as a third party customer.

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

	Three Months Ended June 30,		
	2007	2006	Change
	(In thousands)		
Gas marketing	$ 8,902	$	(100)%
Purchased gas	8,796		(100)%
Gross margin	106		(100)%
General and administrative expenses	119		
Loss from marketing natural gas (1)	$ (13)	$	(100)%

(1) The loss from marketing natural gas is after elimination of inter-segment profit of $93,962.

In order to focus on our core business and the marketing of our production, we will commence to abandon the marketing of natural gas for third parties in the third quarter of 2007. We will transition the marketing activities into GeoMet, Inc. as a functional marketing group and discontinue the operational activities of Shamrock Energy LLC. We do not expect a disruption in the marketing of our gas, incurring significant liabilities or recognizing gains and losses as a result of exiting this business.

Results of Operations Corporate

Three Months Ended June 30, 2007 compared with Three Months Ended June 30, 2006

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.495 million, or 65%, to $1.3 million. The increase was primarily due to higher outstanding debt and slightly higher interest rates. Capitalized interest totaled $0.134 million and $0.295 for the three months ended June 30, 2007 and 2006, respectively.

Income tax expense (benefit). Income tax expense increased by $0.357 million to $1.9 million. The income tax expense increase in the current quarter was due to increased pretax income versus the comparable prior period partially offset by a decrease in the effective tax rate for the current quarter to 39% from 41% in the comparable prior period. The principal driver for the difference in the effective tax rate was that the current period includes Canadian losses that we are not able to recognize a tax benefit.

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Results of Operations Natural Gas Production

Six Months Ended June 30, 2007 compared with Six Months Ended June 30, 2006

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

	Six Months Ended		
		June 30,	
	2007	**2006**	**Change**
	(In thousands)		
Gas sales	$ 25,287	$ 22,451	13%
Operating fees and other	616		100%
Total revenues	$ 25,903	$ 22,451	(15)%
Lease operating expenses	$ 6,794	$ 5,674	(20)%
Compression and transportation expenses	2,867	2,132	(34)%
Production taxes	598	505	(18)%
Depreciation, depletion and amortization	4,341	3,580	(21)%
Research and development		98	NM
General and administrative	4,254	2,456	(83)%
Realized losses (gains) on derivative contracts	(1,296)	156	NM
Unrealized (gains) from the change in market value of open derivative contracts	2,713	(10,445)	NM
Total operating expenses	$ 13,477	$ 4,156	NM
Income (loss) from natural gas production	$ 12,426	$ 18,295	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $2.8 million, or 13%, to $25.3 million compared to the prior six-month period. The increase in gas sales was primarily a result of increased production, which was partially offset by decreased average sales prices. Production increased 22% while average gas prices decreased 8%, excluding hedging transactions. The $2.8 million increase in gas sales consisted of a $4.9 million increase in production, partially offset by a $2.1 million decrease in average prices. The increase in production was principally attributable to the continued development activities at our Gurnee and Pond Creek fields.

Lease operating expenses. Lease operating expenses increased by $1.1 million, or 20%, to $6.8 million. The increase in lease operating expenses consisted of $1.2 million increase in production, partially offset by a $0.124 million decrease in costs.

Compression and transportation expenses. Compression and transportation expenses increased by $0.735 million, or 34%, to $2.9 million. The increase in compression and transportation expenses consisted of a $0.466 million increase in production and a $0.269 million increase in costs. The increase in costs is related to increased transportation costs at our Pond Creek field compared to the prior year quarter.

Production taxes. Production taxes increased by $0.094 million, or 18%, to $0.598 million. The production taxes increase was primarily due to increased production, partially offset by decreasing average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.761 million, or 21%, to $4.3 million. The depreciation, depletion and amortization increase million consisted of a $0.783 million increase in production and $0.022 million decrease in the depletion rate. However, the prior year period includes a $300,000 adjustment to depreciation, depletion and amortization related to the adjustment of certain state taxes not recorded in prior periods. Excluding the $300,000 adjustment, the depletion rate per Mcf increased from $1.15 to $1.30. The increase in the rate is due to increased future development costs and higher cost of drilling.

General and administrative. General and administrative expenses increased by $1.8 million or, 73%, to $4.3 million. The primary drivers for the increased general and administrative expenses were professional services and employee expenses. Professional services consisted of increased audit fees, Sarbanes-Oxley compliance costs, tax services and legal services. Employee expenses increased as a result of increased personnel and higher costs of salary and wages.

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Realized losses (gains) on derivative contracts. Realized gains on derivative contracts increased by $1.5 million to $1.3 million compared to a loss of $0.156 million in the prior period. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses (gains) from the change in market value of open derivative contracts resulted in a $2.7 million loss as compared to a $10.4 million gain in the prior period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair values of derivative liabilities increase. The $2.7 million loss was a result of increased future commodity gas prices.

Results of Operations Marketing Natural Gas

Six Ended Months June 30, 2007 compared with Six Months Ended June 30, 2006

The acquisition of Shamrock Energy LLC on January 1, 2007 (see Note 1 of the unaudited consolidated financial statements) added a second reportable segment, natural gas marketing, to our core business of natural gas exploration, development and production. This entity was previously consolidated as a variable interest entity from August 1 through December 31, 2006. From January 1, 2006 through July 31, 2006, we sold substantially all of our gas production to Shamrock Energy LLC as a third party customer.

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

	Six Months Ended June 30,		
	2007	2006	Change
	(In thousands)		
Gas marketing	$ 17,444	$	(100)%
Purchased gas	17,228		(100)%
Gross margin	216		(100)%
General and administrative expenses	250		
Loss from marketing natural gas(1)	$ (34)	$	(100)%

(1) The loss from marketing natural gas is after elimination of inter-segment profit of $173,873.

In order to focus on our core business and the marketing of our production, we will commence to abandon the marketing of natural gas for third parties in the third quarter of 2007. We will transition the marketing activities into GeoMet, Inc. as a functional marketing group and discontinue the operational activities of Shamrock Energy LLC. We do not expect a disruption in the marketing of our gas, incurring significant liabilities or recognizing gains and losses as a result of exiting this business.

Results of Operations Corporate

Six Months Ended June 30, 2007 compared with Six Months Ended June 30, 2006

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.506 million, or 31%, to $2.1 million. The increase was primarily due to higher outstanding debt and slightly higher interest rates. Capitalized interest totaled $0.446 million and $0.644 for the six months ended June 30, 2007 and 2006, respectively.

Income tax expense (benefit). Income tax expense decreased by $5.6 million to $1.5 million. The decrease in income tax expense for the current period was due to decreased pretax income compared to the prior period. The effective tax rate is comparable between periods; however, the prior period includes a tax adjustment related to certain state taxes not previously included in the current period and the current period includes Canadian losses that we are not able to recognize a tax benefit.

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Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flow from operations for the six months ended June 30, 2007 and 2006 were $10.8 million and $16.5 million, respectively. Cash flow from operations of $10.8 million for the six months ended June 30, 2007, combined together with net cash provided by financing activities of $20.6 million, were sufficient to fund net cash used in investing activities of $29.9 million, which primarily includes capital expenditures for the exploration and development of our gas properties. Net cash provided by financing activities includes $20.5 million related to the credit facility net borrowings.

As of June 30, 2007 and December 31, 2006, we had a working capital deficit of approximately $1.5 million and $1.6 million, respectively. At June 30, 2007, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficits.

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 future equity offerings will provide us with the ability to develop our existing properties and finance our current exploration on unevaluated properties.

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

Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that natural gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily 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 hedged forward for periods of more than two years. We generally limit the amount of these hedges during periods of relatively high financial leverage to no more than 50% to 60% of the then expected gas production for such future period. 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 and a minimum 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 to a predetermined amount, generally between $1.00 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 rise above the level of our hedges and gains during periods where prices drop below the level of our hedges causing significant fluctuations in our statement of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments could materially affect our results of operations depending on the future prices of natural gas. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

We account for our derivative contracts as accounting hedges using mark-to-market accounting under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* As of June 30, 2007, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units. The daily volumes that we hedge are equal during each production period. For our natural gas derivative contracts, summer months apply to April through October and winter months apply to November through March.

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Instrument Type	Production Period	Volumes (MMBtu)	Collars Weighted Average Floor Prices ($/MMBtu)	Collars Weighted Average Cap Prices ($/MMBtu)
Collars (3 way)	July-October 2007	984,000	$ 5.75-$7.38	$ 10.50
Collars (3 way)	Winter 2007/2008	1,216,000	$ 6.00-$9.00	$ 14.80
Collars (3 way)	Summer 2008	1,712,000	$ 5.00-$7.00	$ 10.50
Traditional Collars	July-October 2007	492,000	$ 7.50	$ 9.75
Traditional Collars	Winter 2007/2008	608,000	$ 8.25	$ 11.25

At June 30, 2007 and at December 31, 2006, the fair values of net open derivative contract assets were approximately $2.7 and $5.3 million, respectively.

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market of natural gas may have on the fair value of our derivative instruments. At June 30, 2007, the potential change in the fair value of our derivative contracts assuming a 10% increase in the underlying commodity price was a $1.9 million decrease in the unrealized gain on derivative contracts reported on our unaudited consolidated statements of operations and comprehensive income for the three months ended June 30, 2007.

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.

Capital Expenditures and Capital Resources

The development of coalbed methane fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, the transportation alternatives, and the timing and volume of initial and subsequent natural gas production volumes. We estimate total capital expenditures in 2007 will be approximately $62 million, with $48 million going toward the development of the Gurnee field and Pond Creek field. The decrease in capital expenditures from 2006 is approximately 24% and is primarily attributable to decreased development expenditures at our Gurnee field. We have decided to further reduce our drilling in the Gurnee field from the planned 52 wells to 26 wells to reallocate capital to fund a well treatment program in the Gurnee field, the drilling of several exploratory wells and the expenditures in the projects discussed above in Recent Developments. Capital expenditures for the six months ended June 30, 2007 and 2006 were $29.9 million and $34.6 million, respectively, and have been primarily concentrated in the Pond Creek field, the Gurnee field and in the Peace River Project.

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 $150 million. The borrowing base is subject to semi-annual redeterminations. The lenders also have the right to require one additional redetermination in any fiscal year. Our credit agreement provides for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent s base rate or the federal funds rate plus one half of one percent) or the London Interbank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Borrowings under our credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under our credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our borrowing base) to our consolidated current liabilities is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio of consolidated EBITDA for the four preceding quarters at the end of each fiscal quarter to the sum of our consolidated net interest expense for the same period plus letter of credit fees accruing during such quarter is not permitted to be less than 2.75 to 1. Consolidated EBITDA as defined in the amended credit agreement excludes other non-cash charges deducted in determining net income (loss), which would include unrealized gains and 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 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.

In addition, the borrowing base under our credit facility is re-determined semi-annually and may also be re-determined once each fiscal year for any reason upon request by lenders representing 66.66% of the total commitment under our credit facility. Re-determinations are based upon a number of factors, including commodity prices and reserve levels. The next scheduled re-determination commenced as of June 30, 2007 and will be completed by December 15, 2007. Upon a re-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 credit facility and an acceleration of our indebtedness.

At June 30, 2007, $80.5 million was outstanding under our credit facility. Interest on the borrowings averaged 6.61% per annum. Borrowing availability at June 30, 2007 was $69.5 million. All of the debt outstanding under our 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 credit facility at June 30, 2007, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $805,000.

At June 30, 2007, we did not have any hedges in place to reduce our risk to increases in interest rates.

Contractual Commitments

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

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 3. Quantitative and Qualitative Disclosures About Market Risk

We are engaged primarily in the exploration, development, and production of natural gas from coal seams (coalbed methane) in the U. S. and Canada. We operate in two segments, (i) natural gas exploration, development and production, almost exclusively within the continental United States and British Columbia and (ii) gas marketing in the United States.

As a result, we are exposed to certain market risks that include financial instruments such as short term cash equivalents, accounts receivables, long-term debt, foreign currency and commodity risk. For a discussion of our commodity, interest rate risks and foreign currency risk, see the discussions set forth above in Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations, under the subheadings Liquidity and Capital Resources Price Risk Management Activities, Liquidity and Capital Resources Credit Facility, and Liquidi and Capital Resources Foreign Currency Exchange Rate Risk above.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2007 in ensuring that material information was accumulated and communicated to management, and made known to our chief executive officer and chief financial officer, on a timely basis to allow disclosure as required in this report.

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Changes in Internal Controls Over Financial Reporting

During the period covered by this report, there were no changes that occurred 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

Litigation From time to time, we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, our results of operations or cash flows, if any, will be material except for the litigation discussed below. As of June 30, 2007, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability.

CNX Surface Use Dispute

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

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through the Pond Creek gathering line. On July 30, 2007, we filed our petition for appeal of the portion of the order which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007 CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the tract. 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. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we will be required to seek alternative ways to transport our gas to market. Even assuming such alternatives are available, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company, an affiliate of CNX (Island Creek), in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking 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 seeks $561 million for 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

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Act and Virginia statutory and common law. The suit also alleges CNX s intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX s position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

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We filed a complaint against CNX and Island Creek Coal Company, an affiliate of CNX (Island Creek), in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking 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 seeks $561 million for 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 alleges CNX s intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX s position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

El Paso Overriding Royalty Interest Dispute

We filed a claim in the 116th District Court of Dallas County, Texas on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in the White Oak Creek field in Alabama. We had previously entered into an agreement to sell our interests in the field to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests, and that we are entitled to retain all overriding royalty interests we own in the field. The trial court rendered judgment in our favor, and El Paso appealed the decision of the trial court. The appellate court reversed the trial court s decision in favor of El Paso and remanded the case to the trial court to determine whether El Paso is entitled to specific performance and damages (lost royalties). On August 3, 2007, our petition for a rehearing with the appellate court was denied. We are considering additional including further appeals. To date, El Paso has not paid us the allocated purchase price for the overriding royalties of approximately $10.5 million. We have received royalty payments from the disputed overriding royalty interests of approximately $9.2 million since April 2004. We do not expect the outcome of this dispute to have a material economic effect on our operations, as the economic value of the override is not materially different from its purchase price.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2006.

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.

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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: August 10, 2007

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

INDEX TO EXHIBITS

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

* Attached hereto