GeoMet, Inc.
Form 10-Q
August 10, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2006

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 3208

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. ¨ Yes x 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 7, 2006, there were 38,527,841 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, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 982,964	$ 615,806
Accounts receivable	3,836,526	5,577,140
Current portion of notes receivable	24,469	310,210
Deferred tax asset	313,908	2,911,808
Other current assets	293,510	414,232
Total current assets	5,451,377	9,829,196
Gas Properties utilizing the full cost method of accounting:		
Proved gas properties	267,659,809	229,519,222
Unevaluated gas properties, not subject to amortization	25,565,570	20,680,712
Other property and equipment	2,038,632	1,841,056
Total property and equipment	295,264,011	252,040,990
Less accumulated depreciation, depletion, and amortization	(18,676,912)	(15,392,300)
Property and equipment net	276,587,099	236,648,690
Other noncurrent assets:		
Note receivable	311,677	323,879
Other	937,304	1,107,234
Total other noncurrent assets	1,248,981	1,431,113
TOTAL ASSETS	$ 283,287,457	$ 247,908,999
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 13,693,037	$ 6,861,075
Derivative liability	782,814	8,931,926
Asset retirement liability	52,579	51,510
Accrued liabilities	1,348,003	1,265,989
Current portion of long-term debt	91,626	86,472
Total current liabilities	15,968,059	17,196,972
Long-term debt	73,862,113	99,926,378
Long-term derivative liability	316,048	2,611,592
Asset retirement liability	2,063,534	1,838,663
Other long-term accrued liabilities	258,573	258,573

Deferred income taxes	41,203,622	30,654,545
Total liabilities	133,671,949	152,486,723
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, and 40,000,000 shares; issued and outstanding 32,777,841 and 29,974,664 at June 30, 2006 and December 31, 2005, respectively	32,778	29,975
Paid-in capital	133,807,003	106,408,915
Accumulated other comprehensive income	295,963	56,310
Retained earnings	15,898,245	6,443,928
Less notes receivable	(418,481)	(17,516,852)
Total stockholders equity	149,615,508	95,422,276
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 283,287,457	$ 247,908,999

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, 2006	Three months ended June 30, 2005	Six months ended June 30, 2006	Six months ended June 30, 2005
Revenues:				
Gas sales	$ 10,139,536	$ 7,329,171	$ 22,450,945	$ 13,697,967
Operating fees and other		233,704		371,661
Total revenues	10,139,536	7,562,875	22,450,945	14,069,628
Expenses:				
Lease operating expense	2,832,789	1,810,757	5,673,653	3,894,226
Compression and transportation expense	1,055,148	759,989	2,131,638	1,480,998
Production taxes	236,193	162,124	504,937	287,754
Depreciation, depletion and amortization	1,746,481	1,464,478	3,580,486	2,348,987
Research and development	29,137	319,263	98,392	320,258
General and administrative	1,436,024	804,383	2,455,580	1,555,618
Realized losses (gains) on derivative contracts	(439,368)	301,740	156,204	136,295
Unrealized losses (gains) on derivative contracts	(1,371,124)	(2,169,469)	(10,444,656)	2,669,958
Total operating expenses	5,525,280	3,453,265	4,156,234	12,694,094
Income from operations	4,614,256	4,109,610	18,294,711	1,375,534
Other income (expense):				
Interest income	7,319	8,326	18,213	25,830
Interest expense (net of amounts capitalized)	(765,765)	(870,853)	(1,629,139)	(1,479,986)
Other gains	31,645		18,268)	
Total other income (expense)	(726,801)	(862,527)	(1,592,658)	(1,454,156)
Income (loss) before income taxes and minority interest, net of income tax	3,887,455	3,247,083	16,702,053	(78,622)
Income tax expense (benefit)	1,596,236	1,104,007	7,247,736	(1,733)
Net income (loss) before minority interest , net of income tax	2,291,219	2,143,076	9,454,317	(76,889)
Minority interest, net of income tax		64,423		(442,336)
Net income	$ 2,291,219	$ 2,078,653	$ 9,454,317	$ 365,447
Other comprehensive income, net of income taxes				
Foreign currency translation adjustment, net of income tax of $0	264,703	(13,547)	239,653	(17,539)
Comprehensive Income	$ 2,555,922	$ 2,092,200	$ 9,693,970	$ 382,986
Earnings per common share:				
Basic	$ 0.07	$ 0.07	$ 0.29	$ 0.01
Diluted	$ 0.07	$ 0.07	$ 0.28	$ 0.01

Weighted average number of common shares:				
Basic	32,711,133	28,624,913	32,212,497	26,325,233
Diluted	33,702,095	29,446,999	33,296,767	26,895,590

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Stockholders Equity and Accumulated Other Comprehensive Income

(Unaudited)

	June 30, 2006
Preferred stock, $0.001 par value shares outstanding, none	
Common stock, $0.001 par value shares outstanding:	
Balance at beginning of year	29,974,664
144A offering, sale of common stock	2,317,023
Exercise of stock options	486,154
Balance at end of period	32,777,841
Common stock, $0.001 par value:	
Balance at beginning of year	$ 29,975
144A Offering, Sale of common stock	2,317
Exercise of stock options	486
Balance at end of period	$ 32,778
Paid-in capital:	
Balance at beginning of year	$ 106,408,915
144A Offering, Sale of common stock	28,010,491
Exercise of stock options	857,983
Offering costs	(2,026,305)
Stock-base compensation, including taxes	1,057,672
Accrued interest on all notes receivable issued to purchase common stock, net of income tax	(501,753)
Balance at end of period	$ 133,807,003
Accumulated other comprehensive income:	
Balance at beginning of year	$ 56,310
Foreign currency translation adjustment, net of income tax of $0	239,653
Balance at end of period	$ 295,963
Retained earnings:	
Balance at beginning of year	$ 6,443,928
Net income	9,454,317
Balance at end of period	$ 15,898,245
Notes receivable:	
Balance at beginning of year	$ (17,516,852)
Payments	17,184,357
Accrued interest on notes receivable issued to purchase common stock	(85,986)
Balance at end of period	$ (418,481)

Total Stockholders Equity	$ 149,615,508

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, 2006	Six Months Ended June 30, 2005
Cash flows provided by operating activities:		
Net income	$ 9,454,317	$ 365,447
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	3,350,182	2,448,375
Amortization of debt issuance costs	64,556	84,801
Minority interest		(442,336)
Deferred income taxes	7,492,460	(201,840)
Unrealized losses (gains) from the change in market value of open derivative contracts	(10,444,656)	2,594,853
Stock-based compensation	197,672	
Gain on sale of assets	(19,689)	
Accretion expense	75,665	45,542
Changes in operating assets and liabilities:		
Accounts receivable	1,763,501	822,037
Other current assets	120,722	73,495
Accounts payable	4,354,216	2,888,196
Other accrued liabilities	85,913	(70,649)
Net cash provided by operating activities	16,494,859	8,607,921
Cash flows used in investing activities:		
Capital expenditures	(34,569,868)	(35,716,496)
Proceeds from sale of other property and equipment	112,026	
Collection of notes receivable	297,942	
Other assets	(348,426)	(96,145)
Net cash used in investing activities	(34,508,326)	(35,812,641)
Cash flows provided by financing activities:		
Debt issuance costs	(262,644)	
Dividends		(3,000,000)
Proceeds from exercise of stock options	858,469	326,300
Equity offering costs	(1,309,862)	
Proceeds from sales of common stock	28,012,809	
Credit facility borrowings	41,750,000	29,500,000
Proceeds from notes receivable and accrued interest	17,184,357	
Payments on credit facility and other debt	(67,809,110)	(64,307)
Net cash provided by financing activities	18,424,019	26,761,993
Effect of exchange rate changes on cash	(43,394)	(19,089)
Increase (decrease) in cash and cash equivalents	367,158	(461,816)
Cash and cash equivalents at beginning of period	615,806	3,013,723
Cash and cash equivalents at end of period	$ 982,964	$ 2,551,907

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. GeoMet is 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. GeoMet operates in one segment, natural gas exploration, development and production, almost exclusively within the continental United States and British Colombia, Canada.

These unaudited consolidated financial statements reflect, in the opinion of the Company s 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 Financial Statements and Notes included in the Company s S-1 for the fiscal year ended December 31, 2005.

On April 13, 2005, GeoMet acquired, through a stock exchange, the minority interest in its 81% owned subsidiary and merged the subsidiary into GeoMet. Following the merger, GeoMet changed its name from GeoMet Resources, Inc. to GeoMet, Inc.

Note 2 Recent Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes or FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes. The interpretation prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. We are currently evaluating the impact of this new interpretation.

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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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Earnings per share:				
Basic-net income per share	$ 0.07	$ 0.07	$ 0.29	$ 0.01
Diluted-net income per share	$ 0.07	$ 0.07	$ 0.28	$ 0.01
Numerator				
Net income available to common stockholders basic	$ 2,291,219	$ 2,078,653	$ 9,454,317	$ 365,447
Denominator				
Weighted average shares outstanding-basic	32,711,133	28,624,913	32,212,497	26,325,233
Add potentially dilutive securities:				
Stock Options	990,962	822,086	1,084,270	570,357
Dilutive securities	33,702,095	29,446,999	33,296,767	26,895,590

Note 4 Gas Properties

The Company uses the full cost method of accounting for its 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, the Company capitalizes interest expense, direct general and administrative expenses, direct stock-based compensation expense, and additions resulting from asset retirement liabilities. To the extent that capitalized costs of gas properties, net of accumulated depreciation, depletion and amortization, exceed the discounted future net revenues of proved gas reserves net of deferred taxes, such excess capitalized costs would be charged to operations. No such charges to operations were required during the three and six months ended June 30, 2006

Note 5 Asset Retirement Liability

The Company records an asset retirement obligation (ARO) on the consolidated balance sheet and capitalizes the asset retirement costs in gas properties in the period in which the retirement obligation is incurred if a reasonable estimate of the fair value of an obligation can be made. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date the abandonment obligation was incurred using an assumed cost of funds for the Company. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed cost of funds.

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The following table details the changes to the Company s asset retirement liability for the six months ended June 30, 2006:

Asset retirement obligation at beginning of year	$ 1,890,173
Liabilities incurred	207,627
Liabilities settled	(33,680)
Accretion expense	85,336
Revisions in estimates	(38,814)
Foreign currency translation	5,471
Asset retirement obligation at end of period	2,116,113
Less: current portion of obligation	52,579
Long-term asset retirement obligation	$ 2,063,534

Note 6 Price Risk Management Activities

The Company engages in price risk management activities from time to time. These activities are intended to manage the Company s exposure to fluctuations in the price of natural gas. The Company utilizes derivative financial instruments, primarily 3-way collars and swaps, as the means to manage this price risk. Under collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company.

The Company has elected not to designate any of its current derivative contracts as accounting hedges under FASB 133, Accounting for Derivative Instruments and Hedging Activities, and accordingly, accounted for its derivative contracts using mark-to-market accounting. During the three and six months ended June 30, 2006, the Company recognized gains on derivative contracts of $1,810,492 and $10,288,452 including realized gains of $439,368 and losses of $156,204, respectively. During the three months ended June 30, 2005, the Company recognized gains on derivative contracts of $1,867,729 including realized losses of $301,740. During the six months ended June 30, 2005, the Company recognized losses on derivative contracts of $2,806,253 including realized losses of $136,295.

As of June 30, 2006, 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.

Instrument Type	**Production Period**	**Volumes (MMBtu)**	**Weighted Average Floor Price ($/MMBtu)**	**Cap ($/MMBtu)**
Collars (3 way)	April 1-December 31, 2006	2,086,000	$ 6.12-7.35	$9.23
Collars (3 way)	January 1-October 31, 2007	1,756,000	$ 6.60-7.98	$10.28

Note 7 Long-Term Debt

The following is a summary of long-term debt at June 30, 2006 and December 31, 2005:

	June 30, 2006	**December 31, 2005**
Borrowings under bank credit facility	$ 73,000,000	$ 99,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	210,227	243,166
	142,613	146,571

Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured		
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	600,899	623,113
Total debt	73,953,739	100,012,850
Less current maturities included in current liabilities	(91,626)	(86,472)
Total long-term debt	$ 73,862,113	$ 99,926,378

The Company initially entered into a bank credit facility in December 2001. In January 2006, the Company amended and restated its bank credit facility and, among other things, extended the maturity date to January 6, 2011. Pursuant to the credit agreement (as amended), the Company has a $150 million revolving credit facility that permits the Company to borrow amounts from time to time based on the available borrowing base as determined in the bank credit facility. The bank credit facility is secured by substantially all of the Company s gas properties and the stock

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of its subsidiaries. The borrowing base under the bank credit facility is based upon the valuation as of June 30 and December 31 of each year of the Company s gas properties 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. 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.

As of June 30, 2006, the borrowing base under the bank credit facility was $150 million of which $73 million of borrowings were outstanding, resulting in a borrowing availability of $77 million. For the six months ended June 30, 2006 we borrowed $41.7 million and made payments of $67.7 million under the credit facility. As of June 30, 2006 outstanding balances on the revolving credit facility bear interest at either the bank s Adjusted Base Rate, which is the bank s base rate but never less than the Federal Funds Rate plus 0.5%, or the Adjusted LIBOR rate plus a margin of 1.00% to 2.00% based on borrowing base usage.

The Company is subject to certain restrictive financial and non-financial covenants under the bank credit facility, 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 facility agreement. As of June 30, 2006, the Company was in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on January 6, 2011.

Note 8 Common Stock

Effective January 24, 2006, GeoMet s Board of Directors approved a four-for-one common stock split and increased the authorized capital stock of the Company from 40,000,000 shares of common stock at December 31, 2005 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, we completed a private equity offering of 10,000,000 shares of our common stock, consisting of 2,067,023 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 $25.0 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 the offering, together with the proceeds from the repayment of the selling stockholders loans, to repay a portion of the borrowings under our bank credit facility and for general corporate purposes. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers from which we received aggregate consideration of approximately $3.0 million, or $12.09 per share, pursuant to the initial purchaser s option to purchase additional shares. The net proceeds generated from this sale were used to repay a portion of the borrowings under our bank credit facility and for general corporate purposes

For the six months ended June 30, 2006, a total of 486,154 shares of common stock were issued upon the exercise of stock options.

Note 9 Stock Options

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. The exercise price of the options granted was equal to the estimated market value of the Company s 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 the Company s 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 (SFAS 123R), using the prospective transition method. Due to the adoption of SFAS 123R, we expect our compensation expense related to the granting of share-based awards subsequent to adoption to be higher than in prior periods. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, no equity compensation cost will be recognized on these awards in the future unless such awards are modified, repurchased or cancelled.

As of June 30, 2006, the Company has two plans, the 2005 Stock Option Plan and the 2006 Long-Term Incentive Plan. The 2005 Stock Option Plan authorizes the granting of incentive stock options to key employees.

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The exercise price of each option may not be less than 100% of the fair market value of a share of common stock on the date of grant. The options have a term of seven years, vest evenly over four years, and become exercisable on each of the first four anniversary dates of issuance. Prior to the effective date of the merger, the option entitled the holder to acquire shares of the Company s majority-owned subsidiary. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under this plan became fully vested and were exchanged for options to acquire common stock of GeoMet. The option tables for the years ended 2004 and 2003 have been converted into equivalent options of GeoMet. There will be no future grants of awards under the 2005 Stock Option Plan.

The 2006 Long-Term Incentive Plan authorized the granting of stock 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. This plan is available to our employees and independent directors and is designed to (1) attract and retain employees and independent directors, (2) further align their interest with shareholder interest and (3) closely link compensation with Company s 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 have a term of ten years, vest evenly over three years, except for awards that are performance based. Performance based awards vest when the performance criteria has been met.

Qualified Stock Options

The table below summarizes qualified stock option activity for the six months ended June 30, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2005	893,324	$ 2.55	3.60	
Granted	150,945	13.00	6.90	
Forfeited				
Exercised	326,154	$ 1.52		
Outstanding at June 30, 2006	718,115	$ 5.27	4.21	$ 5,552,465
Options exercisable at June, 2006	501,170	$ 2.63	3.19	$ 5,552,465

The total intrinsic value (current market price less option strike price) of options exercised during the six months ended June 30, 2006 was $3.8 million, and the Company received $0.4 million in cash.

Non-Qualified Stock Options

In conjunction with the sale of common stock to certain executive officers of the Company during 2000, we granted these officers options to acquire 400,000 shares of common stock of GeoMet at $2.50 per share. The holders of the options also had a right to be issued additional options to acquire five percent of any additional common stock issued at a price of $2.50 per share. The executive officers were issued options to acquire 600,000 shares in conjunction with the issuance of 12,000,000 common shares in 2003 and were issued options to acquire 200,000 shares in conjunction with the issuance of 4,000,000 common shares in 2004. The options have a term of 10 years and are fully vested and exercisable.

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The table below summarizes non-qualified stock option activity for the six months ended June 30, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2005	1,200,000	$ 2.50	3.60	
Granted	73,865	13.00	6.90	
Forfeited				
Exercised	160,000	$ 2.50		
Outstanding at June 30, 2006	1,113,865	$ 3.13	6.60	$ 10,920,000
Options exercisable at June, 2006	1,040,000	$ 2.50	6.60	$ 10,920,000

The total intrinsic value (current market price less option strike price) of options exercised during the three months ended March 31, 2006 was $1.7 million, and the Company received $0.4 million in cash.

During the three months ended March 31, 2006, the Company recorded a compensation expense accrual in the amount of $205,923 for an employee who exercised his options via a cashless exercise with no mature shares on the date of exercise. The total compensation expense accrual was then allocated to the full cost pool and lease operating expenses in the amount of $102,961 and $102,962, respectively.

During the three months ended June 30 2006, we granted share-based option awards to certain directors (8,000 options under the 2006 Plan), executive officers and key employees (65,865 performance-based non-qualified options and 12,249 shares of restricted stock under the 2006 Plan) and executive officers and key employees (150,945 incentive stock options under the 2006 Plan). We recorded a compensation accrual of $120,301, ($2,041 charged to lease operating expense, $92,669 charged to general and administrative expense and $16,068 capitalized in the domestic full cost pool and $9,523 capitalized to unevaluated gas properties). A related income tax benefit of $19,541 was also recorded. For future compensation cost associated with these awards totaling $667,946 will be amortized over the vesting period of such options. Compensation cost related to share based awards is determined using the fair value method as described above. Significant assumptions used in determining the compensation cost include an expected term of 4.5 years, volatility of 36.95%, a risk free interest rate of 4.87% and no expected dividends. The performance criteria of the performance-based options and restricted stock awards include attaining certain levels of production, natural gas reserves and net income. None of the goals have been achieved as of June 30, 2006.

The following table illustrates the approximated pro forma effect on net income and earnings per share assuming the stock-based compensation expense under APB 25 had been recorded using fair value methods at date of grant for the following prior periods:

	Three Months Ended	Six Months Ended
	June 30, 2005	
Net income as reported	$ 2,078,653	$ 365,447
Less stock-based compensation expense determined under fair value based methods, net of tax	40,009	44,796
Pro Forma net income	$ 2,038,644	$ 320,651
Net income per share:		
Basic-as reported	$ 0.07	$ 0.01
Basic-pro forma	$ 0.07	$ 0.01
Diluted-as reported	$ 0.07	$ 0.01

Diluted-pro forma	$	0.07	$	0.01

Significant assumptions used in determining the compensation costs for the above table included a dividend yield of 0%, expected volatility of 0%, risk-free interest rate of 3.4% and an expected life term of 3 years.

Note 10 Commitments and Contingencies

Litigation From time to time the Company is a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management does not believe that the adverse effect on its financial condition, results of operations or cash flows of the Company, if any, will be material. As of June 30, 2006, there were no known environmental or other regulatory matters related to the Company s operations which are reasonably expected to result in a material liability to the Company.

El Paso Overriding Royalty Interest Dispute

The Company filed a claim on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of its rights under a joint operating agreement covering certain properties in White Oak Creek. The Company had previously entered into an agreement to sell its interest 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. The Company has asserted that the preferential right to purchase does not include overriding royalty interests, and that the Company is entitled to retain all overriding royalty interests the Company possesses under the agreement. The trial court rendered judgment in the Company s favor, and El Paso has appealed the decision of the trial court. While the Company believes that it is entitled to retain these interests, a judgment against the Company would result in it being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds the Company has received from production since the effective date of the sale.

CNX Surface Use Dispute

The Company and Pocahontas Mining Limited Liability Company (PMC) filed a claim in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX Gas Company LLC (CNX) seeking a temporary and permanent injunction, as well as a declaration of the Company s rights under a right-of-way agreement that the Company entered into with PMC, the surface owner. The Company is in the process of constructing a 12-mile pipeline, a portion of which traverses this right-of-way to connect with and transport our gas to the Jewell Ridge Pipeline. CNX has claimed that it has the exclusive right to transport gas across the acreage in question and that the Company s right-of-way is invalid. CNX has gated certain access roads to the acreage and requested that the Company remove its contractor s equipment from the property. The Circuit Court of Buchanan County, Virginia conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings the court directed the parties to prepare a scheduling order setting forth the timelines for discovery and setting the trial date for this matter for November 15, 2006. On June 30, 2006, CNX filed a counterclaim against PMC and the Company seeking a declaratory judgment from the court that CNX has superior rights to the Company s 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.

The Company believes that its right-of-way agreement is valid and enforceable and that the Company will prevail in the lawsuit; however, in the event the Company is unsuccessful in obtaining a favorable declaratory judgment, the Company may be required to construct an alternate pipeline at a cost in excess of $12 million, change the planned route of the pipeline the Company is currently constructing at a cost that could add more than $5 million to the cost of construction of the pipeline, pay CNX an access fee for any gas transported across the PMC property at a rate up to 3.5% of the gross proceeds from the sale of such gas, or seek other transportation alternatives through pipelines owned by third parties. The Company does not know what the cost of other transportation alternatives with third parties would be at this time, but the Company believes that such cost would be significantly in excess of the costs related to the construction and operation of its own pipeline. Any of these alternatives may result in the Company s inability to deliver its gas from the Pond Creek field to market for an extended period of time. If the Company is unable to deliver its gas to market for a prolonged period of time, the Company s financial position, results of operations and cash flow will be materially adversely affected.

Note 11 Related Party Transactions

On July 21, 2003, GeoMet loaned the Chief Financial Officer $250,000 to provide liquidity in connection with a divorce settlement so that the Chief Financial Officer could retain ownership of his common stock. The full recourse loan accrued interest at an annual rate of 5.87%. The note was paid in full on January 2006 concurrent with the private offering discussed in note 8.

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Note 12 Income Taxes

The Company records our income taxes using an asset and liability approach in accordance with the provisions of the SFAS 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 bases of assets and liabilities using enacted tax rates at the end of the period. Under SFAS 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 Internal Revenue Code Section 382. The Company has a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that the Company will use these NOLs to offset current tax liabilities in future years.

Deferred income tax expense was increased by $405,722 during the three months ended March 31, 2006 and for the six months ended June 30, 2006 because of certain state taxes not previously included in prior periods.

On May 18, 2006, the Governor of Texas signed into law House Bill 3 (HB-3) which modifies the existing Texas franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent tax rate. HB-3 becomes effective for activities occurring on or after January 1, 2007. We believe that this tax should still be accounted for as an income tax, following the provisions of SFAS 109, because it has the characteristics of an income tax. For the three and six months ended June 30, 2006, we believe that the impact of this modified tax is not significant.

Note 13 Subsequent Events

On July 27, 2006, the Securities and Exchange Commission declared effective the Company s registration statement on Form S-1 (Registration No. 333-131716), which registered for sale with the Securities and Exchange Commission 10,250,000 shares of common stock issued in the private offering discussed in note 9. Also on July 27, 2006, the Securities and Exchange Commission declared effective the Company s registration statement on Form S-1 (Registration No. 333-134070), which registered 5,750,000 shares of its common stock for sale in an underwritten initial public offering. The initial public offering closed on August 2, 2006, and the price per share was set at $10.00 per share. The Company received net proceeds from the offering of approximately $52.6 million, after deducting estimated offering expenses and underwriting discounts and commissions. The Company used the net proceeds from the offering to reduce outstanding borrowings under our bank credit facility.

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

Statement Regarding Forward-Looking Information

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe , anticipate , estimate , expect , intend , and similar 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 the Company s audited consolidated financial statements for the fiscal year ended December 31, 2005, which are included in our final prospectuses that we filed with the Securities and Exchange Commission on July 28, 2006.

Overview

We are an independent natural gas producer involved in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). 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, 2006, we control a total of approximately 266,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia.

We have been very active in North America for over twenty years as an operator of CBM fields owned by us, as a contract operator for CBM fields in which we owned an interest, and as a consultant or contract operator for CBM fields owned by other companies. Over the last five years, we have focused on expanding the number of projects that we own and operate. This focus resulted in the initial development of our two primary producing properties, the Gurnee field in the Cahaba Basin and the Pond Creek field in the Appalachian Basin. Additionally, we own and operate several active exploration projects. This change in focus of our operations has also resulted in a significant increase in our business, ranging from capital expenditures to headcount.

On January 30, 2006, we sold 2,067,023 shares of common stock in a private placement to qualified institutional buyers pursuant to Rule 144A under the Securities Act. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers under Rule 144A under the Securities Act pursuant to the initial purchaser s option to purchase additional shares. We used the net proceeds from our private placement of common stock of approximately $27 million and the receipt of approximately $17.5 million from the repayment of certain stockholder loans and from the exercise of stock options by certain of the selling stockholders to reduce outstanding borrowings under our bank credit facility and for general corporate purposes.

On August 2, 2006, we sold 5,750,000 shares of common stock in an initial public offering. We received net proceeds from the offering of approximately $52.6 million, after deducting estimated offering expenses and underwriting discounts and commissions, and used the net proceeds from the offering to reduce outstanding borrowings under our bank credit facility.

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, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes, 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.

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For the three and six months ended June 30, 2006, gas sales increased by 412.4 MMcf and 772.6 MMcf from the comparable periods in the prior year to 1.5 Bcf and 2.8 Bcf, respectively. The increase in sales was related to the continued development of our Cahaba and Pond Creek fields. In addition, average gas sales prices for the three and six months ended June 30, 2006 were unchanged for the three months ended June 30, 2006 and increased by $1.28 per Mcf for the six months ended June 30, 2006 from the comparable periods in the prior year to $6.81 per Mcf and $7.89 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. Our policy is to enter into hedging transactions which increase our probability of achieving our targeted level of cash flows. As a result of these hedging positions, we had unrealized gains in the amount of $1.4 million and $10.4 million for the three and six months ended June 30, 2006, respectively, compared to an unrealized gain of $2.2 million for the three months ended June 30, 2005 and an unrealized loss of $2.7 million for the six months ended June 30, 2005.

We believe that our cash flow from operations and other financial resources such as borrowings under our credit facility, proceeds from the initial public equity offering concluded on July 27, 2006 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.

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, 2006.

Future Charges

Public Company Expenses

We believe that our general and administrative expenses will increase now that we are a publicly traded company. This increase will consist of legal and accounting fees and additional expenses associated with compliance with the Sarbanes-Oxley Act of 2002 and other regulations. We anticipate that our ongoing general and administrative expenses will also increase as a result of being a publicly traded company. This increase will be due primarily to the cost of accounting support services, filing annual and quarterly reports with the Securities and Exchange Commission, investor relations, directors fees, directors and officers insurance, and registrar and transfer agent fees. As a result, we believe that our general and administrative expenses for 2006 will increase significantly over the prior year.

Stock Compensation

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards (SFAS) No. 123R, Share-Based Payment (SFAS 123R), using the prospective transition method. Due to the adoption of SFAS 123R, we expect our compensation expense related to the granting of share-based awards subsequent to adoption to be higher than in prior periods. As of June 30, 2006, future compensation expense totals $667,946 for awards granted subsequent to January 1, 2006. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, no equity compensation cost will be recognized on these awards in the future unless such awards are modified, repurchased or cancelled.

Derivative Instruments

Due to the historical volatility of natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our sales. Currently, we use collars and fixed-price swaps as our mechanism for hedging commodity prices. We have elected not to designate any of our current derivative instruments as hedges for accounting purposes in accordance with SFAS No. 133 Derivative Instruments and Hedging Activities. As a

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result, we account for our derivative instruments on a mark-to-market basis, and changes in the fair 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. If commodity prices increase, we may recognize additional charges in future periods; however, for the three and six months ended June 30, 2006 prices decreased, and we recognized a total gain on derivative contracts in the amount of $1.8 million and $10.3 million, respectively. The three months ended June 30, 2006 total gain consisted of $1.4 million unrealized gain and $0.4 million realized gain while the six months ended June 30, 2006 total gain consisted of $10.4 unrealized gain and $0.1 realized loss.

Producing Field 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, 2006 and 2005. This table should be read with the discussion of the results of operations for the periods presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
	(In thousands except for per Mcf)			
Gas sales	$ 10,140	$ 7,329	$ 22,451	$ 13,698
Lease operating expenses	$ 2,833	$ 1,811	$ 5,674	$ 3,894
Compression and transportation expenses	$ 1,055	$ 760	$ 2,132	$ 1,481
Production taxes	$ 236	$ 162	$ 505	$ 288
Total production expenses	$ 4,124	$ 2,733	$ 8,310	$ 5,663
Net sales volumes (MMcf)	1,489	1,078	2,845	2,073
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 6.81	$ 6.81	$ 7.89	$ 6.61
Average natural gas sales price realized(1)	$ 7.10	$ 6.52	$ 7.84	$ 6.54
Lease operating expenses	$ 1.90	$ 1.68	$ 1.99	$ 1.88
Compression and transportation expenses	$ 0.71	$ 0.71	$ 0.75	$ 0.71
Production taxes	$ 0.16	$ 0.15	$ 0.18	$ 0.14
Total production expenses	$ 2.77	$ 2.54	$ 2.92	$ 2.73
Depreciation, depletion & amortization	$ 1.17	$ 1.36	$ 1.26	$ 1.13

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

Results of Operations

Three Months Ended June 30, 2006 compared with Three Months Ended June 30, 2005

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

	Three Months Ended June 30,		
	2006	**2005**	**Change**
	(In thousands)		
Gas sales	$ 10,140	$ 7,329	38%
Operating fees and other		234	(100)%
Total revenues	$ 10,140	$ 7,563	34%
Lease operating expenses	$ 2,833	$ 1,811	56%
Compression and transportation expenses	1,055	760	39%
Production taxes	236	162	46%
Depreciation, depletion and amortization	1,746	1,464	19%
Research and development	29	319	(91)%
General and administrative	1,436	804	79%
Realized losses (gains) on derivative contracts	(439)	302	(246)%
Unrealized (gains) from the change in market value of open derivative contracts	(1,371)	(2,169)	(37)%

Total operating expenses	$ 5,525	$ 3,453	60%
Interest expense, net of amounts capitalized	$ (766)	$ (871)	(12)%
Income before income taxes and minority interest, net of income tax	$ 3,887	$ 3,247	20%
Income tax expense	1,596	1,104	45%
Net income before minority interest, net of income tax	$ 2,291	$ 2,143	7%

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Gas sales. Gas sales increased by $2.8 million, or 38%, to $10.1 million compared to the prior year quarter. The increase in gas sales was primarily a result of increased production. Production increased 38% while average gas prices were flat, excluding hedging transactions. The increase in production was principally attributable to our Cahaba and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $1.0 million, or 56% to $2.8 million. The increase in lease operating expenses consisted of $0.693 million increase in production and $0.329 increase in costs. The increase in costs is related to increased well services.

Compression and transportation expenses. Compression and transportation expenses increased by $0.295 million, or 39% to $1 million. The $0.295 million increase in compression and transportation expenses consisted of a $0.291 million increase in production and a $0.004 million increase in costs.

Production taxes. Production taxes increased by $0.074 million, or 46%, to $0.236 million. The production taxes increase of $0.239 million consisted of a $0.062 million increase in production and a $0.012 million increase in costs.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.282 million, or 19%, to $1.7 million. The depreciation, depletion and amortization increase of $0.282 million consisted of a $0.560 million increase in production, partially offset by $0.278 decrease in depletion rate. The decrease in the depletion rate was primarily due to increased reserves from the development of our core fields.

General and administrative. General and administrative expenses increased by $0.632 million or, 79%, to $1.4 million. The increase in general and administrative expenses was a result of increases in employee expenses (21%), professional services (156%), director expenses (100%), office expenses and business taxes (131%). This increase was partially offset by decreased insurance expenses (46%), increased capitalized general and administrative expenses (17%) and field and operating overhead recoveries (21%). The largest dollar increase was in professional services that resulted from the increased audit, tax and legal services and employee expenses. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of preparing to be a public company.

Realized losses (gains) on derivative contracts. Realized gains on derivative contracts increased by $0.741 million to $0.439 million compared to a loss of $0.302 million in the prior corresponding 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 (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 $1.4 million gain as compared to a $2.2 million gain in the comparable period in 2005. 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 value of derivative liabilities increase. The $1.4 million gain was a result of decreased future commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.105 million, or 12%, to $0.766 million. The decrease was primarily due to lower outstanding bank balances, partially offset by higher interest rates. The decrease in interest expense was also offset by decreased capitalization of interest expense to our gas properties. Capitalized interest totaled $0.349 million for the three months ended June 30, 2006.

Income tax expense (benefit). Income tax expense increased by $0.492 million, or 45%, to $1.6 million. The increase in income tax expense in the current quarter was due to (1) the pretax income position versus a pretax loss position in the comparable prior period and (2) an increase in the effective tax rate for the current quarter to 41% from 34% in the comparable prior period as a result of certain state taxes not previously included in prior periods.

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Six Months Ended June 30, 2006 compared with Six Months Ended June 30, 2005

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

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Change
	(In thousands)		
Gas sales	$ 22,451	$ 13,698	64%
Operating fees and other		372	(100)%
Total revenues	$ 22,451	$ 14,070	60%
Lease operating expenses	$ 5,674	$ 3,894	46%
Compression and transportation expenses	2,132	1,481	44%
Production taxes	505	287	75%
Depreciation, depletion and amortization	3,580	2,349	52%
Research and development	98	320	(69)%
General and administrative	2,456	1,556	58%
Realized losses on derivative contracts	156	136	15%
Unrealized losses (gains) from the change in market value of open derivative contracts	(10,445)	2,670	(491)%
Total operating expenses	$ 4,156	$ 12,694	(67)%
Interest expense, net of amounts capitalized	$ (1,629)	$ (1,480)	10%
Income (loss) before income taxes and minority interest, net of income tax	$ 16,702	$ (79)	NM
Income tax expense (benefit)	7,248	(2)	NM
Net income (loss) before minority interest, net of income tax	$ 9,454	$ (77)	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $8.7 million, or 64%, to $22.4 million compared to the prior year quarter. The increase in gas sales was a result of increased production and average gas prices. Production increased 37% while average gas prices, excluding hedging transactions, increased 19%. The $8.7 million increase in gas sales consisted of a $3.6 million increase in prices and a $5.1 million increase in production. The increase in production was principally attributable to our Cahaba and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $1.8 million, or 46% to $5.7 million. The $1.8 million increase in lease operating expenses consisted of $1.5 million increase in production and $0.330 increase in costs.

Compression and transportation expenses. Compression and transportation expenses increased by $0.651 million, or 44% to $2.1 million. The $0.651 million increase in compression and transportation expenses consisted of a $0.552 million increase in production and a $0.099 million increase in costs. The increase in cost per Mcf was a result of additional compressors and increases in transportation fees to support the increase in production levels.

Production taxes. Production taxes increased by $0.217 million, or 75%, to $0.505 million. The production taxes increase of $0.217 million consisted of a $0.110 million increase in costs and a $0.107 million increase in production. The increase in production taxes was a result of increased production and the increase in costs was a result reduced tax exemptions at certain fields.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.2 million, or 52%, to $3.6 million. The depreciation, depletion and amortization increase of $1.2 million consisted of a $0.356 million increase in depletion rate and a $0.875 million increase in production. The increase in the depletion rate was primarily due to $48.0 million added to the net book value of gas properties due to a purchase accounting adjustment related to the acquisition of the minority interest stock in a subsidiary.

General and administrative. General and administrative expenses increased by $0.900 million or 58%, to $2.5 million. The increase in general and administrative expenses was a result of increases in employee expenses (11%), professional services (192%), director expenses (100%), and office expenses and business taxes (200%). This increase was partially offset by decreased insurance expense (46%), increased capitalized general and administrative

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expenses (25%) and field and operating overhead recoveries (34%). The largest dollar increase was in professional services that resulted from the increased audit, tax and legal services and employee expenses. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of preparing to be a public company.

Realized losses on derivative contracts. Realized losses on derivative contracts increased by $0.019 million to $0.156 million compared to a loss of $0.136 million in the prior corresponding 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 generated a $10.4 million gain as compared to a $2.7 million loss in the comparable period in 2005. 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 value of derivative liabilities increase. The $10.4 million gain was a result of decreased commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.149 million, or 10%, to $1.6 million. The increase was primarily due to higher outstanding bank balances and higher interest rates. Capitalized interest totaled $0.644 million for the six months ended June 30, 2006.

Income tax expense (benefit). Income tax expense (benefit) resulted in expense of $7.2 million in the compared to a benefit of $0.002 million in the comparable prior period in 2005. The increase in income tax expense in the current quarter was due to the pretax income position versus a pretax loss position in the comparable prior period and an increase in the effective tax rate for the current quarter to 43% from 2.2% in the comparable prior period as a result of certain state taxes not previously included in prior periods and the related cumulative non-cash adjustment of $0.406 million. Excluding the state tax revision, the revised estimated effective tax rate for the year is expected to be approximately 40.1%.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flow from operations for the six months ending June 30, 2006 and 2005 were $16.5 million and $8.6 million, respectively. Cash flow from operations for the six months ended June 30, 2006 of $16.5 million combined together with net proceeds of the private offering of $28 million and proceeds from the collection of notes receivable of $17.2 million were sufficient to fund our capital expenditures of $34.6 million and the repayment of our revolving credit facility and other debt of $26.1 million.

As of June 30, 2006 and December 31, 2005, we had a working capital deficit of approximately $11.1 million and $7.4 million, respectively. The increase in the working capital deficit was primarily a result of decreased accounts receivable, decreased deferred tax assets, increased accounts payable, and increased deferred tax liabilities. This increase in the working capital deficit was partially offset by increased cash and cash equivalents and decreased net derivative liabilities. At June 30, 2006, 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, proceeds from the initial public equity offering concluded on July 27, 2006 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.

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Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that 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 through the use of commodity price swap agreements and costless collar arrangements. 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. We have 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. Currently, our hedge strategy favors the use of three-way collars that allow us to retain more price upside. We have not designated any of our price risk management activities as accounting hedges and, therefore, 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. Until 2005, the impact of this method of accounting was not significant; however, the significant increase in gas prices in 2005, particularly in the third quarter in response to Hurricanes Katrina and Rita resulted in significant unrealized losses. More recently, the decrease in gas market price has created significant unrealized gains. The unrealized gains and losses have no impact on cash flows.

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.

As indicated above, we have elected not to designate any of our current derivative contracts as accounting hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and accordingly, accounted for our derivative contracts using mark-to-market accounting. During the three and six months ended June 30, 2006 prices decreased and we recognized a total gain on derivative contracts in the amount of $1.8 million and $10.3 million, respectively. The three months ended June 30, 2006 total gain consisted of $1.4 million unrealized gain and $0.4 million realized gain while the six months ended June 30, 2006 total gain consisted of $10.4 million unrealized gain and $0.2 million realized loss.

As of July 5, 2006, 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. The following table includes open derivative contracts that were in outstanding as of June 30, 2006 and new contracts that were entered into on July 5, 2006.

Instrument Type	Production Period	Volumes (MMBtu)	Weighted Average Floor Prices ($/MMBtu)		Weighted Average Cap Prices ($/MMBtu)
Collars (3 way)	Summer 2006	2,568,000	$ 5.88	$7.00	$ 8.49
Collars (3 way)	Winter 2006/2007	1,510,000	$ 6.70	$8.20	$ 11.02
Collars (3 way)	Summer 2007	1,712,000	$ 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

At June 30, 2006 and at December 31, 2005, the fair values of open derivative contracts were liabilities of approximately $1.1 million and $11.5 million, respectively.

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Sensitivity analyses of the incremental effects on pre-tax gain for the six months ended June 30, 2006 of a hypothetical 10% and 25% change in natural gas prices for outstanding hedge contracts as of June 30, 2006 are provided in the following table:

	Incremental (increase) decrease in pre-tax gain assuming a hypothetical price Increase and decrease of (1)	
	10%	25%
Price increase	$ (1,736)	$ (4,670)
Price decrease	$ 1,530	$ 3,373

(1) We remain at risk for possible changes in the market value of these derivative contracts; however, any unfavorable increases would be partly offset by higher revenues due to higher sales prices for our gas. The favorable effect of this offset is not reflected in the sensitivity analyses.

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 CBM fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, and the timing and volume of initial and subsequent natural gas production. We estimate total capital expenditures in 2006 will be approximately $90 million with approximately 80% allocated to development projects, 12% to exploration projects, 4% to leasehold acquisitions and the remaining 4% for other items (primarily capitalized overhead and interest and administrative capital expenditures), representing an increase of approximately $30 million over our actual 2005 capital expenditures. The increase is primarily attributable to increased development expenditures at Pond Creek and Cahaba. Capital expenditures for the six months ended June 30, 2006 and 2005 were$34.6 million and $35.7 million, respectively and have been primarily concentrated at Pond Creek and Cahaba and British Columbia.

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 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

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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 is to occur as of June 30, 2006 and will be completed by December 15, 2006. 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, 2006, $73 million was outstanding under our credit facility. Interest on the borrowings averaged 6.175% per annum. Borrowing availability at June 30, 2006 was $77 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, 2006, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $730,000.

At June 30, 2006, 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.

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we have the right, from August 1, 2006 to January 31, 2007, to acquire all of the outstanding equity interests and assets of Shamrock once Mr. Gipson acquires the outstanding equity interests of Shamrock pursuant to an agreement Mr. Gipson has entered into with Optigas. In exchange for this option, we agreed (i) to extend our gas marketing agreement with Shamrock for a term ending no earlier than January 31, 2007, (ii) to advance, on or before August 1, 2006, $90,000 to Shamrock for working capital purposes during the option period, (iii) to provide any guaranties on behalf of Shamrock for transactions that Shamrock enters into during the option period that require such guaranties, up to an aggregate of $1,500,000, and (iv) to advance up to an additional $50,000 to Shamrock as may be required to cover certain expenses of Shamrock prior to January 31, 2007, the date on which our option to purchase Shamrock expires.

In the event that we exercise the option, we will be obligated to provide Mr. Gipson an at-will employment position with us at an annual salary of not less than $130,000, and we will also pay Mr. Gipson an amount equal to 50% of the net profits generated by Shamrock from August 1, 2006 through the date that we elect to exercise the option, up to January 31, 2007. No additional consideration is due upon our exercise of this option. In the event we do not exercise the option by January 31, 2007 and Mr. Gipson continues to operate Shamrock after the end of the option period, Shamrock will retain 100% of the net profits generated during the option period, all guaranties that we have entered into on behalf of Shamrock will terminate on January 31, 2007, and Shamrock will repay us all funds that we advanced to Shamrock in equal amounts, without interest, over an 18-month period. If we do not exercise the option by January 31, 2007 and Mr. Gipson elects not to continue to operate Shamrock, Mr. Gipson will wind up the affairs of Shamrock within 90 days after the end of the option period, and we will receive 100% of the net profits from the operations during the wind-up period and the proceeds from the liquidation of Shamrock s assets until we have been repaid all funds that we advanced to Shamrock and all guaranties that we entered into on behalf of Shamrock have been terminated and released.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Foreign Currency Exchange Rate Risk

We began exploratory operations in Canada in the fourth quarter of 2004 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.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are engaged in engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane) in the U. S. and Canada. 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 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, 2006 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.

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.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time we are a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial condition, results of operations or cash flows.

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 White Oak Creek. We had previously entered into an agreement to sell our interest 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 possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. While we believe that we are entitled to retain these interests, a judgment against us would result in our being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

CNX Surface Use Dispute

We and Pocahontas Mining Limited Liability Company (PMC) filed a claim in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX Gas Company LLC (CNX) seeking a temporary and permanent injunction as well as a declaration of our rights under a right-of-way agreement that we entered into with PMC, the surface owner. We are in the process of constructing a 12-mile pipeline, a portion of which traverses this right-of-way to connect with and transport our gas to the Jewell Ridge Pipeline. CNX has claimed that it has the exclusive right to transport gas across the acreage in question and that our right-of-way is invalid. CNX has gated certain access roads to the acreage and requested that we remove our contractor s equipment from the property. The Circuit Court of Buchanan County, Virginia conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings the court ordered CNX to allow us and PMC access to the property over and across the existing roads and directed the parties to prepare a scheduling order setting forth timelines for discovery and setting the trial date for this matter for November 15, 2006. 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.

We believe that our right-of-way agreement is valid and enforceable and that we will prevail in our lawsuit; however, in the event we are unsuccessful in obtaining a favorable declaratory judgment, we may be required to construct an alternate pipeline at a cost in excess of $12 million, change the planned route of the pipeline we are currently constructing at a cost that could add more than $5 million to the cost of construction of the pipeline, pay CNX an access fee for any gas transported across the PMC property at a rate up to 3.5% of the gross proceeds from the sale of such gas, or seek other transportation alternatives through pipelines owned by third parties. We do not know what the cost of other transportation alternatives with third parties would be at this time, but we believe that such cost would be significantly in excess of the costs related to the construction and operation of our own pipeline. Any of these alternatives may result in our inability to deliver our gas from the Pond Creek field to market for an extended period of time. If we are unable to deliver our gas from the Pond Creek field to market for a prolonged period of time, our financial position, results of operations and cash flow will be materially adversely affected.

Item 1A. Risk Factors

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

Our revenue, profitability, and cash flow depend upon the prices and demand for natural gas. The market for natural gas is very volatile and even relatively modest drops in prices can significantly affect our financial results and

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impede our growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

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

Many of these factors may be beyond our control. Because all of our estimated proved reserves as of December 31, 2005 were natural gas reserves, our financial results are sensitive to movements in natural gas prices. Earlier in this decade, natural gas prices were much lower than they are today. Lower natural gas prices may not only decrease our revenues on a per Mcf basis, but also may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carry amount may not be recoverable or whenever management s plans change with respect to those assets. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

We face uncertainties in estimating proved gas reserves, and inaccuracies in our estimates could result in lower than expected reserve quantities and a lower present value of our reserves.

Natural gas reserve engineering requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels, and operating and development costs. In addition, in the early stages of a coalbed methane project, it is difficult to predict the production curve of a coalbed methane field. The estimated production profile of a field in the early stage of operations may vary significantly from the actual production profile as the field matures. As a result, quantities of estimated proved reserves, projections of future production rates, and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing, and production. Also, we make certain assumptions regarding future natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on current prices and costs. However, actual future net cash flows from our gas properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;

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- assumptions governing future prices;
- the amount and timing of actual production;
- future gas prices and operating costs; and
- capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from estimated proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Unless we replace our natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, results of operations, and cash flows.

Producing natural gas reservoirs are typically characterized by declining production rates that vary depending upon reservoir characteristics and other factors. CBM production generally declines at a shallow rate after initial increases in production which result as a consequence of the dewatering process. The rate of decline from our existing wells may change in a manner different than we have estimated. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find, or acquire additional reserves to replace our current and future production at acceptable costs.

Currently the vast majority of our producing properties are located in two counties in Alabama, one county in West Virginia, and one county in Virginia, making us vulnerable to risks associated with having our production concentrated in a few areas.

The vast majority of our producing properties are geographically concentrated in two counties in Alabama, one county in West Virginia, and one county in Virginia. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters, interruption of transportation of natural gas produced from the wells in these basins, or other events which impact these areas.

Our ability to market the gas we produce depends in substantial part on the availability and capacity of pipelines systems owned and operated by third parties. Operational impediments on these pipeline systems may hinder our access to natural gas markets or delay our production.

The availability of a ready market for our natural gas production depends on a number of factors, including the proximity of our reserves to pipelines, capacity constraints on pipelines, and disruption of transportation of natural gas through pipelines. We transport the natural gas we produce principally through pipelines owned by third parties. If we cannot access these third-party pipelines, or if transportation of gas through any of these pipelines is disrupted, we may be required to shut in or curtail production from some of our wells or seek alternate methods of transportation of our production. If any of these were to occur, our revenues would be would be reduced, which would in turn have a material adverse effect on our financial condition and results of operations.

The natural gas we produce from the Pond Creek field in the Appalachian Basin is gathered at our central dehydration and compression facility and is delivered into the Cardinal States Gathering Company (Cardinal States) gathering system for redelivery into the Columbia Gas Transmission Corporation gas pipeline system. Our gathering agreement with Cardinal States terminates on April 30, 2007. However, we are currently constructing a 12-mile pipeline to transport the natural gas we produce from the Pond Creek field into the Jewell Ridge Pipeline, which is currently being constructed by East Tennessee Natural Gas, LLC, a subsidiary of Duke Energy Corporation. Upon completion of our new pipeline, it will no longer be necessary for us to access the Cardinal States gathering system to transport our gas to market. Pocahontas Mining Limited Liability Company (PMC) owns a portion of the land through which our new pipeline will be constructed and has granted us an easement to construct the pipeline on this land under a right-of-way agreement. CNX Gas Company LLC (CNX), the parent company of Cardinal States, has recently notified us that it believes that the pipeline right-of-way granted to us by PMC is invalid and that it has the exclusive right to transport natural gas across PMC s property. Thereafter, CNX gated certain access roads to PMC s property, impeding the construction of our pipeline; however, we have continued constructing the pipeline on acreage to which we have access.

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We and PMC have applied for a temporary and permanent injunction in the Circuit Court of Buchanan County, Virginia to prevent CNX from impeding our access to the property and are also seeking a declaration of our rights under the right-of-way agreement. The court conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings, the court ordered CNX to allow us and PMC access to the property over and across the existing roads and directed the parties to prepare a scheduling order setting forth timelines for discovery and setting the trial date for this matter for November 15, 2006. 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.

In the event we are unsuccessful in obtaining a favorable declaratory judgment, we may be required to construct an alternate pipeline at a cost in excess of $12 million, change the planned route of the pipeline we are currently constructing at a cost that could add more than $5 million to the cost of construction of the pipeline, pay CNX an access fee for any gas transported across the PMC property at a rate up to 3.5% of the gross proceeds from the sale of such gas, or seek other transportation alternatives through pipelines owned by third parties. We do not know what the cost of other transportation alternatives with third parties would be at this time, but we believe that such cost would be significantly in excess of the costs related to the construction and operation of our own pipeline. Any of these alternatives may result in our inability to deliver the gas we produce from the Pond Creek field to market for some period of time. If we are unable to deliver our gas to market for a prolonged period of time, our financial position, results of operations and cash flow will be materially adversely affected.

We may be unable to obtain adequate acreage to develop additional large-scale projects.

To achieve economies of scale and produce gas economically, we need to acquire large acreage positions to reduce our per unit costs. There are a limited number of coalbed formations in North America that we believe are favorable for CBM development. We face competition when acquiring additional acreage, and we may be unable to find or acquire additional acreage at prices that are acceptable to us.

Our exploration and development activities may not be commercially successful.

The exploration for and production of natural gas involves numerous risks. The cost of drilling, completing, and operating wells for coalbed methane or other gas is often uncertain, and a number of factors can delay or prevent drilling operations or production, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pipeline ruptures; and

unavailability or high cost of drilling rigs, other field services, and equipment.

Our future drilling activities may not be successful, and our drilling success rates could decline. Unsuccessful drilling activities could result in higher costs without any corresponding revenues.

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We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, and issuances of common stock. Our future contractual commitments from January 1, 2006 through December 31, 2011 total $150 million and include debt service, operating lease obligations, firm transportation obligations and other obligations, collectively aggregating approximately $18 million during 2006, $25 million during 2007 to 2010, and $107 million during 2011 to 2012, when our existing credit facility matures. We also require capital to fund our drilling budget, which is expected to be $90 million for 2006. We will be required to meet our needs from our internally generated cash flow, debt financings, and equity financings.

If our revenues decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. Our revolving credit facility contains covenants restricting our ability to incur additional indebtedness without the consent of the lender. There can be no assurance that our lender will provide this consent or as to the availability or terms of any additional financing. If we incur additional debt, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- a leveraged financial position would make us more vulnerable to economic downturns and could limit our ability to withstand competitive pressures; and
- any debt that we incur under our revolving credit facility will be at variable rates which makes us vulnerable to increases in interest rates. For example, a 1% increase in interest rates based upon our debt outstanding as of December 31, 2005 would result in an additional $990,000 of interest expense.

Even if additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our projects, which in turn could lead to a possible loss of properties and a decline in our natural gas reserves.

Our credit facility contains a number of financial and other covenants, and our obligations under the credit facility are secured by substantially all of our assets. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.

Our credit facility subjects us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, or pay dividends on our common stock. We are also required by the terms of our credit facility to comply with certain financial ratios. Our credit facility also provides for periodic redeterminations of our borrowing base, which may affect our borrowing capacity. Our credit facility is secured by a lien on substantially all of our assets, including equity interests in our subsidiaries. A more detailed description of our credit facility is included in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and the footnotes to our consolidated financial statements included elsewhere in this prospectus.

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 redetermined semi-annually and may be redetermined at other times upon request by the lenders under certain circumstances. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. The next scheduled redetermination is to occur as of June 30, 2006 and will be completed by December 15, 2006. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the credit facility and an acceleration of our indebtedness.

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We operate in a highly competitive environment and many of our competitors have greater resources than we do.

The gas industry is intensely competitive and we compete with companies from various regions of the United States and Canada and may compete with foreign suppliers for domestic sales, many of whom are larger and have greater financial, technological, human and other resources. If we are unable to compete, our operating results and financial position may be adversely affected. For example, one of our competitive strengths is as a low-cost producer of gas. If our competitors can produce gas at a lower cost than us, it would effectively eliminate our competitive advantage in that area.

In addition, larger companies may be able to pay more to acquire new properties for future exploration, limiting our ability to replace gas we produce or to grow our production. Our ability to acquire additional properties and to discover new reserves also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

The coalbeds from which we produce gas frequently contain water that may hamper our ability to produce gas in commercial quantities or affect our profitability.

Unlike conventional natural gas production, coalbeds frequently contain water that must be removed in order for the gas to desorb from the coal and flow to the well bore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce gas in commercial quantities. The cost of water disposal may affect our profitability.

We may face unanticipated water disposal costs.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to shut in wells, reduce drilling activities, or upgrade facilities. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- our wells produce excess water; or
- new laws and regulations require water to be disposed of in a different manner.

Our identified drilling locations are scheduled over a period in excess of five years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage located in the Pond Creek field and the Cahaba Basin. As of December 31, 2005, we had identified and scheduled 586 gross drilling locations on this acreage. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas prices, the availability of capital, costs, drilling results, our ability to transport our gas to market, regulatory approvals and other factors. Because of these uncertainties, we do not know if all of the potential drilling locations we have identified will ever be drilled or if we will be able to produce natural gas from these or any other potential drilling locations. In addition, unless we drill a minimum number of wells annually on this acreage, the leases covering such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our operations in British Columbia present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

We conduct our operations in British Columbia through our wholly owned subsidiary, Hudson s Hope Gas Ltd. Our operations in British Columbia may be adversely affected by currency fluctuations. The expenses of such operations are payable in Canadian dollars. As a result, our

Canadian operations are subject to risk of fluctuations in the relative value of the Canadian and United States dollars. Other risks of operations in Canada include, among other things, increases in taxes and governmental royalties and changes in laws and policies governing operations of foreign-based companies. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our operations in British Columbia.

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We may be unable to retain our existing senior management team and/or our key personnel that has expertise in coalbed methane extraction and our failure to continue to attract qualified new personnel could adversely affect our business.

Our business requires disciplined execution at all levels of our organization to ensure that we continually develop our reserves and produce gas at profitable levels. This execution requires an experienced and talented management and production team. If we were to lose the benefit of the experience, efforts and abilities of any of our key executives or the members of our team that have developed substantial expertise in coalbed methane extraction, our business could be adversely affected. We have not entered into, and do not expect to enter into employment agreements or non-competition agreements with any of our key employees, other than J. Darby Seré, our Chief Executive Officer and President, and William C. Rankin, our Executive Vice President and Chief Financial Officer. We do not maintain key person life insurance on any of our personnel. Our ability to manage our growth, if any, will require us to continue to train, motivate, and manage our employees and to attract, motivate, and retain additional qualified managerial and production personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating, and retaining the personnel required to grow and operate our business profitably.

Government laws, regulations, and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business increase our costs and may restrict our operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state, local, and foreign authorities, relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, control of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our respective costs of operations and competitive position. In addition, we could incur substantial costs, including clean-up costs, fines and civil or criminal sanctions, and third party damage claims for personal injury, property damage, wrongful death, or exposure to hazardous substances, as a result of violations of or liabilities under environmental and health and safety laws.

Additionally, the gas industry is subject to extensive legislation and regulation, which is under constant review for amendment or expansion. Any changes may affect, among other things, the pricing or marketing of gas production. State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing, and well site restoration. If we fail to comply with statutes and regulations, we may be subject to substantial penalties, which would decrease our profitability.

We must obtain governmental permits and approvals for drilling operations, which can be a costly and time consuming process and result in restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations. For example, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that proposed exploration for or production of gas may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

We have limited protection for our technology and depend on technology owned by others.

We use operating practices that management believes are of significant value in developing CBM resources. In most cases, patent or other intellectual property protection is unavailable for this technology. Our use of independent contractors in most aspects of our drilling and some completion operations makes the protection of such technology more difficult. Moreover, we rely on the technological expertise of the independent contractors that we retain for our operations. We have no long-term agreements with these contractors, and thus we cannot be sure that we will continue to have access to this expertise.

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We may incur additional costs to produce gas because our confirmation of title for gas rights for some of our properties may be inadequate or incomplete.

We generally obtain title opinions on significant properties that we drill or acquire. However, we cannot be sure that we will not suffer a monetary loss from title defects or failure. In addition, the steps needed to perfect our ownership varies from state to state and some states permit us to produce the gas without perfected ownership under forced pooling arrangements while other states do not permit this. As a result, we may have to incur title costs and pay royalties to produce gas on acreage that we control and these costs may be material and vary depending upon the state in which we operate.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical, and from time to time there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment, and supplies are substantially greater. As a result of historically strong prices of gas, the demand for oilfield services has risen, and the costs of these services are increasing. If the unavailability or high cost of drilling rigs, equipment, supplies, or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our natural gas production, we have entered into natural gas price hedging arrangements with respect to a portion of our expected production. We will most likely enter into additional hedging transactions in the future. While intended to reduce the effects of volatile natural gas prices, such transactions may limit our potential gains and increase our potential losses if natural gas prices were to rise substantially over the price established by the hedge. For example, as a consequence of increases in natural gas prices during the year ended December 31, 2005, we recognized total losses on our outstanding hedges of approximately $19.5 million (consisting of a $7.5 million realized loss and a $12 million unrealized loss). Based upon the hedges we had in place at December 31, 2005, hypothetical 10% and 25% increases in natural gas prices would have increased our pre-tax loss by approximately $4.9 million and $12.9 million, respectively. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected; or
- the counterparties to our hedging agreements fail to perform under the contracts.

We do not insure against all potential operating risks. We may incur substantial losses and be subject to substantial liability claims as a result of our natural gas operations.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. Although we maintain insurance at levels we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations.

Disclosure Regarding Forward-Looking Statements

This quarterly report on Form 10-Q and the documents incorporated by reference in this report contain forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

our growth strategies;

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- our ability to successfully and economically explore for and develop natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as may, will, expect, anticipate, estimate and similar words, althoug some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

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

(a) None.

(b) The following use of proceeds information is being provided with respect to our registration statement on Form S-1 (File No. 333-134070) which was declared effective by the Securities and Exchange Commission on July 27, 2006.

The offering of our common stock, par value $0.001 per share, commenced on July 27, 2006 following the effectiveness of our registration statement on Form S-1 (File No. 333-134070). 5,750,000 shares of our common stock registered under the Securities Act pursuant to that registration statement were issued and sold on August 2, 2006 at a public offering price of $10.00 per share. The offering terminated after the issue and sale of shares of our common stock pursuant on August 2, 2006.

Banc of America Securities LLC, A.G. Edwards & Sons, Inc., and Raymond James & Associates, Inc. acted as representatives of the underwriters in the offering. The offering generated gross proceeds of $57,500,000 to us and net proceeds of approximately $52,600,000 to us, after deducting the underwriting discount of $4,025,000 and other estimated expenses of $850,000 related to the offering. After the payment of offering expenses, we used the net proceeds of the offering to repay a portion of the outstanding indebtedness under our credit facility. None of the offering expenses or net proceeds were direct or indirect payments to our directors, officers, affiliates, or to a person owning 10% more of our common stock.

(c) None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holdings

During the period covered by this report, on April 17, 2006 by written consent, a majority of our stockholders approved and adopted our 2006 Long-Term Incentive Plan, which reserved 2,000,000 shares of our common stock for issuance under the terms of the 2006 Plan.

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Item 5. Other Information.

On June 27, 2006, we entered into an underwriting agreement with Banc of America Securities LLC, A.G. Edwards & Sons, Inc., and Raymond James & Associates, Inc. as representatives of the underwriters. In accordance with the terms and conditions of the underwriting agreement, we agreed to sell to the underwriters 5,000,000 shares of our common stock, par value $.001 per share, and grant the underwriters an option to purchase up to an additional 750,000 shares of common stock to cover over-allotments. The underwriters exercised the option simultaneously with the closing of the offering on August 2, 2006. The underwriting agreement contains customary representations, warranties and agreements of us and customary conditions to closing, indemnification rights and obligations of the parties and termination provisions. The underwriting agreement is filed as Exhibit 1.1 to this report and is incorporated herein by reference.

Item 6. Exhibits and Reports on Form 8-K

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, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GeoMet Inc.

Date: August 10, 2006

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

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INDEX TO EXHIBITS

Exhibit Number	Exhibits
1.1*	Underwriting Agreement dated July 27, 2006 among GeoMet, Inc. and Banc of America Securities, LLC, A.G. Edwards & Sons, Inc., and Raymond James & Associates, Inc.
3.1	Amended and Restated Certificate of Incorporation of GeoMet, Inc. (incorporated by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1/A (No. 333-131716) filed on July 25, 2006).
3.2	Amended and Restated Bylaws of GeoMet, Inc. (incorporated by reference to Exhibit 3.2 to the Company s Registration Statement on Form S-1/A (No. 333-131716) filed on July 25, 2006).
10.1	Third Amended and Restated Credit Agreement dated June 9, 2006, among GeoMet, Inc., Bank of America, N.A., as Administrative Agent, and BNP Paribas, as Syndication Agent (incorporated by reference to Exhibit 10.8 to the Company s Registration Statement on Form S-1/A (No. 333-131716) filed on June 21, 2006).
10.2	GeoMet, Inc. 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to the Company s Registration Statement on Form S-1/A (No. 333-131716) filed on May 12, 2006).
10.3	Option Agreement dated June 13, 2006 between Jon M. Gipson and GeoMet, Inc. (incorporated by reference to Exhibit 10.11 to the Company s Registration Statement on Form S-1/A (No. 333-131716) filed on June 21, 2006.)
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