GeoMet, Inc.
Form 10-Q
November 13, 2009
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2009

OR

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

For the transition period from ______ to ______

Commission File Number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

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

N/A

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ¨ Yes ¨ No

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x	Smaller reporting company	¨

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

As of November 1, 2009, there were 39,466,790 shares issued and outstanding of GeoMet, Inc. s common stock, par value $0.001 per share.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Part I. Financial Information

Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2009	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 818,347	$ 2,096,561
Accounts receivable, both amounts net of allowance of $60,848	1,765,604	5,364,456
Inventory	2,317,916	3,339,228
Derivative assets	2,641,289	6,596,360
Other current assets	635,126	541,311
Total current assets	8,178,282	17,937,916
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	458,544,407	447,968,536
Unevaluated gas properties, not subject to amortization		5,017
Other property and equipment	3,496,677	3,429,890
Total property and equipment	462,041,084	451,403,443
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(342,235,534)	(93,104,323)
Property and equipment net	119,805,550	358,299,120
Other noncurrent assets:		
Derivative assets	1,080	723,669
Deferred income taxes	46,169,568	
Other	557,749	639,648
Total other noncurrent assets	46,728,397	1,363,317
TOTAL ASSETS	$ 174,712,229	$ 377,600,353
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 6,234,067	$ 13,384,675
Accrued liabilities	2,807,568	2,623,640
Deferred income taxes	568,348	2,426,798
Derivative liabilities	876,062	714,903
Asset retirement liability	113,675	117,423
Current portion of long-term debt	120,090	111,767
Total current liabilities	10,719,810	19,379,206
Long-term debt	120,015,954	117,117,955
Asset retirement liability	4,706,935	4,348,938
Other long-term accrued liabilities	81,454	105,890

Derivative liabilities	933,339	374,489
Deferred income taxes		43,841,950
TOTAL LIABILITIES	136,457,492	185,168,428
Commitments and contingencies (Note 10)		
Stockholders Equity:		
Preferred stock, $0.001 par value authorized 10,000,000, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 39,466,790 and 39,305,152 at September 30, 2009 and December 31, 2008, respectively	39,467	39,050
Treasury stock 10,432 shares	(93,811)	(93,811)

Table of Contents

	September 30, 2009	December 31, 2008
Paid-in capital	189,509,448	188,692,242
Accumulated other comprehensive loss	(1,931,440)	(2,399,992)
Retained (deficit) earnings	(149,032,213)	6,422,772
Less notes receivable	(236,714)	(228,336)
Total stockholders equity	38,254,737	192,431,925
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 174,712,229	$ 377,600,353

See accompanying Notes to Consolidated Financial Statements (Unaudited).

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Revenues:				
Gas sales	$ 6,393,469	$ 18,674,209	$ 22,683,888	$ 54,956,315
Operating fees and other	97,032	146,093	271,966	647,250
Total revenues	6,490,501	18,820,302	22,955,854	55,603,565
Expenses:				
Lease operating expense	3,195,088	3,475,373	11,112,575	10,866,943
Compression and transportation expense	1,234,764	1,129,425	4,049,729	3,177,620
Production taxes	248,150	599,237	855,805	1,655,282
Depreciation, depletion and amortization	5,168,938	2,523,737	10,187,376	7,472,332
Impairment of gas properties	69,145,938		236,440,515	
General and administrative	1,852,991	2,098,060	7,006,492	7,477,767
Realized (gains) losses on derivative contracts	(3,169,060)	1,389,952	(8,626,180)	2,021,188
Unrealized losses (gains) on derivative contracts	3,567,270	(21,564,961)	5,525,502	(820,369)
Total operating expenses (income)	81,224,079	(10,349,177)	266,551,814	31,850,763
Operating (loss) income from continuing operations	(74,753,578)	29,169,479	(243,595,960)	23,752,802
Other income (expense):				
Interest income	5,514	15,767	21,148	35,830
Interest expense (net of amounts capitalized)	(1,385,846)	(1,117,553)	(3,787,293)	(3,538,022)
Other	4,579	18,047	12,311	47,390
Total other income (expense)	(1,375,753)	(1,083,739)	(3,753,834)	(3,454,802)
(Loss) income before income taxes	(76,129,331)	28,085,740	(247,349,794)	20,298,000
Income tax benefit (expense)	27,786,346	(10,604,417)	91,894,809	(8,135,244)
Net (loss) income	$ (48,342,985)	$ 17,481,323	$ (155,454,985)	$ 12,162,756
(Loss) earnings per share:				
Net (loss) income				
Basic	$ (1.24)	$ 0.45	$ (3.98)	$ 0.31
Diluted	$ (1.24)	$ 0.44	$ (3.98)	$ 0.31
Weighted average number of common shares:				
Basic	39,139,906	38,872,218	39,063,294	38,821,764
Diluted	39,139,906	39,838,826	39,063,294	39,714,176

See accompanying Notes to Consolidated Financial Statements (Unaudited).

5

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive (Loss) Income

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
Net (loss) income	$ (48,342,985)	$ 17,481,323	$ (155,454,985)	$ 12,162,756
Gain (loss) on foreign currency translation adjustment, net of tax	203,045	(198,303)	384,309	(530,187)
Gain (loss) on interest rate swap, net of tax	53,044	(75,309)	84,243	(80,495)
Other comprehensive (loss) income	$ (48,086,896)	$ 17,207,711	$ (154,986,433)	$ 11,552,074

See accompanying Notes to Consolidated Financial Statements (Unaudited).

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2009	2008
Cash flows provided by operating activities:		
Net (loss) income	$ (155,454,985)	$ 12,162,756
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	10,187,376	7,472,332
Impairment of gas properties	236,440,515	
Amortization of debt issuance costs	147,099	129,458
Deferred income tax (benefit) expense	(91,880,770)	8,122,744
Unrealized losses (gains) from the change in market value of open derivative contracts	5,525,502	(820,369)
Stock-based compensation	661,263	485,757
Loss on sale of assets	31,076	20,512
Accretion expense	323,726	257,528
Changes in operating assets and liabilities:		
Accounts receivable	3,680,724	(1,663,697)
Other current assets	(272,210)	(2,069,906)
Accounts payable	(2,402,377)	2,211,140
Other accrued liabilities	(125,530)	(1,338,138)
Net cash provided by operating activities	6,861,409	24,970,117
Cash flows used in investing activities:		
Capital expenditures	(11,066,497)	(36,567,273)
Proceeds from sale of other property and equipment	19,165	26,000
Other assets	(65,201)	28,816
Net cash used in investing activities	(11,112,533)	(36,512,457)
Cash flows provided by financing activities:		
Proceeds from exercise of stock options		75,025
Proceeds from revolver borrowings	33,150,000	89,000,000
Payments on revolver	(30,150,000)	(77,000,000)
Purchase of treasury stock	(613)	(23,359)
Payments on other debt	(93,678)	(86,048)
Net cash provided by financing activities	2,905,709	11,965,618
Effect of exchange rate changes on cash	67,201	(10,500)
(Decrease) increase in cash and cash equivalents	(1,278,214)	412,778
Cash and cash equivalents at beginning of period	2,096,561	1,540,516
Cash and cash equivalents at end of period	$ 818,347	$ 1,953,294

See accompanying Notes to Consolidated Financial Statements (Unaudited).

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(Unaudited)

Note 1 Organization and Our Business

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

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements for the fiscal year ended December 31, 2008 and the accompanying notes included in our Annual Report on Form 10-K, which we filed with the Securities and Exchange Commission (the SEC) on March 13, 2009.

Note 2 Recent Pronouncements

FASB Accounting Standards Codification In June 2009, the Financial Accounting Standards Board (FASB) issued ASC 105 (formerly SFAS 168), The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (ASC 105). ASC 105 has become the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernment entities. It also modifies the GAAP hierarchy to include only two levels of GAAP; authoritative and non-authoritative. The Company adopted ASC 105 effective July 1, 2009. Pursuant to the provisions of ASC 105, the Company has updated references to GAAP in its financial statements issued for the period ended September 30, 2009. The adoption of ASC 105 did not have an impact on the Company s financial position, results of operations or cash flows.

Fair Value Measurements and Disclosures In August 2009, the FASB issued Accounting Standards Update No. 2009-05 (ASC Update 2009-05), an update to ASC 820, Fair Value Measurements and Disclosures. This update provides amendments to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities. Among other provisions, this update provides clarification that in circumstances, in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the valuation techniques described in ASC Update 2009-05. ASC Update 2009-05 will become effective for the Company s annual financial statements for the year ended December 31, 2009. The adoption of ASC Update 2009-05 is not expected to have a material impact on the Company s financial position, results of operations or cash flows.

Subsequent Events In May 2009, the FASB issued FASB ASC 855-10-25 (Prior authoritative literature: FASB Statement 165, Subsequent Events). The standard does not require significant changes regarding recognition or disclosure of subsequent events, but does require disclosure of the date through which subsequent events have been evaluated for disclosure and recognition. The standard is effective for financial statements issued after June 15, 2009. The implementation of this standard did not have a significant impact on the financial statements of the Company. Subsequent events through the filing date of this Quarterly Report on Form 10-Q have been evaluated for disclosure and recognition.

Recent FASB Staff Positions On July 1, 2009, we adopted, effective for interim and annual periods ending after June 15, 2009:

(1) Determining Fair Value When Market Activity Has Decreased FASB ASC 820-10-65 (Prior authoritative literature: FASB Statement 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly), which applies to all assets and liabilities (i.e., financial and nonfinancial), reemphasizes that the objective of fair value remains unchanged (i.e., an exit price notion) ASC 820-10-65 provides application guidance on measuring fair value when the volume and level of activity has significantly decreased and identifying

transactions that are not orderly. ASC 820-10-65 also emphasizes that an entity cannot presume that an observable transaction price is not orderly even when there has been a significant decline in the volume and level of activity. ASC 820-10-65 also requires enhanced disclosures.

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

(2) Other-Than-Temporary Impairment (OTTI) FASB ASC 320-10-65 (Prior authoritative literature: FASB FSP 115-2/124-2, Recognition and Presentation of Other-Than-Temporary Impairments) provides a new OTTI model for debt securities only. Equity securities will continue to apply the existing OTTI model. The FSP shifts the focus for debt securities from an entity s intent to hold until recovery to its intent to sell. ASC 320-10-65 also requires entities to initially apply the provisions of the standard to certain previously other-than-temporarily impaired debt instruments existing as of the date of initial adoption by making a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The cumulative-effect adjustment reclassifies the noncredit portion of a previously other-than-temporarily impaired debt security held as of the date of initial adoption from retained earnings to accumulated other comprehensive income. ASC 320-10-65 also requires enhanced disclosures.

(3) Interim Fair Value Disclosures for Financial Instruments FASB ASC 270-10-05 (Prior authoritative literature: APB 28-1, Interim Disclosures About Fair Value of Financial Instruments) expands the fair value disclosures required for all financial instruments within the scope of FASB ASC 825-10-50 (Prior authoritative literature: FASB Statement 107, Disclosures About Fair Value of Financial Instruments) to interim periods. The disclosure requirements of ASC 270-10-05 only apply to public entities. ASC 270-10-05 does not require interim disclosures of credit or market risks also discussed in FASB ASC 825-10-50.

The adoption of the aforementioned three FASB Staff Positions had no material impact on Consolidated Financial Statements (Unaudited) or the accompanying Notes to Consolidated Financial Statements (Unaudited).

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

Commodity Prices Economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used. Therefore, an entity will no longer be able to perform a ceiling limitation test using natural gas prices in effect at a date subsequent to the balance sheet date but prior to the issuance of the consolidated financial statements if there is a significant increase in natural gas prices.

Disclosure of Unproved Reserves Probable and possible reserves may be disclosed separately on a voluntary basis.

Proved Undeveloped Reserve Guidelines Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.

Reserve Estimation Using New Technologies Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Reserve Personnel and Estimation Process Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

Non-Traditional Resources The definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. We are currently evaluating the new rules and assessing the impact they will have on our reported proved natural gas reserves. The SEC is coordinating with the FASB to obtain the revisions necessary to ASC 932 (Prior authoritative literature: FASB Statement 69, Disclosures About Oil and Gas Producing Activities an amendment of FASB Statements No. 19, 25, 33, and 39) to provide consistency with the new rules.

In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC will consider delaying the compliance date.

On October 29, 2009, the SEC released Staff Accounting Bulletin No. 113 (SAB 113). SAB 113 revises or rescinds portions of the interpretive guidance included in the section of the Staff Accounting Bulletin Series titled Topic 12: Oil and Gas Producing Activities (Topic 12) and revises a technical reference in Topic 3: Senior Securities (Topic 3). This update is intended to make the relevant interpretive guidance consistent with current authoritative accounting and auditing guidance and Commission rules and regulations. The principal changes involve revision or removal of material due to recent Commission rulemaking. Specifically, the staff is updating the Series in order to bring existing guidance into conformity with Modernization of Oil and Gas Reporting rules, issued December 31, 2008. SAB 113 also updates related interpretive

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

responses and examples in Topic 12. The staff expects registrants to apply the updated guidance in SAB 113 related to Topic 12 on a prospective basis effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The impact on the Company will be that the Company will no longer be able to perform a ceiling limitation test using natural gas prices in effect at a date subsequent to the balance sheet date but prior to the issuance of the consolidated financial statements if there is a significant increase in natural gas prices.

Note 3 (Loss) Income Per Share

(Loss) Earnings Per Share of Common Stock Basic (loss) earnings per share is calculated by dividing net (loss) income by the weighted average number of shares of common stock outstanding during the period. Fully diluted (loss) earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net (loss) income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive earnings per share consider the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of the numerator and denominator is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Net (loss) income per share:				
Basic-net (loss) income per share	$ (1.24)	$ 0.45	$ (3.98)	$ 0.31
Diluted-net (loss) income per share	$ (1.24)	$ 0.44	$ (3.98)	$ 0.31
Numerator				
Net (loss) income available to common stockholders	$ (48,342,985)	$ 17,481,323	$ (155,454,985)	$ 12,162,756
Denominator:				
Weighted average shares outstanding-basic	39,139,906	38,872,218	39,063,294	38,821,764
Add potentially dilutive securities:				
Stock options and non-vested restricted stock		966,608		892,412
Weighted average shares and potential dilutive shares outstanding	39,139,906	39,838,826	39,063,294	39,714,176

Diluted net per share for the three and nine months ended September 30, 2009 excluded the effect of outstanding options to purchase 2,419,283 shares and 318,414 shares of restricted stock because we reported a net loss, which caused the options and shares of restricted stock to be anti-dilutive.

Note 4 Gas Properties

The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the SEC. Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into cost centers for United States of America and Canada.

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

Estimation of proved natural gas reserves relies on petroleum engineering techniques and assumptions, as well as professional judgment, and the use of factors that cannot be precisely determined. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during future reporting periods. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of proved natural gas reserves which would have a significant impact on the depletion rate.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling limitation test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling limitation test is imposed separately for our U.S. and Canadian cost centers. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling limitation test is calculated using natural gas prices in effect as of the balance sheet date, adjusted for location differentials, held constant over the life of the reserves; however, as allowed by the guidelines of the SEC, significant increases in natural gas prices subsequent to quarter end are used in the ceiling limitation test. In addition, subsequent to the adoption of FASB ASC 410-20-25 (Prior authoritative literature:, FASB Statement 143, Accounting for Asset Retirement Obligations), the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling limitation test calculation.

At September 30, 2009, the carrying value of the Company s gas properties in the U.S. and Canada exceeded the full cost ceiling limitation by $71.2 million, net of income tax of $44.0 million, based upon a natural gas price of approximately $3.38 per Mcf in effect at that date. However, as allowed by the guidelines of the SEC, since gas prices have significantly increased subsequent to September 30, 2009, a recalculation of the ceiling limitation has been performed based upon a natural gas price of approximately $4.43 per Mcf in effect at October 30, 2009, adjusted for location differentials. The result of the recalculation was that the net book value of our full cost pool exceeded the ceiling limitation. Therefore, for the three months ended September 30, 2009, impairments recorded to gas properties were:

	United States	Canada	Total
Impairment of gas properties	$ 69,100,414	$ 45,524	$ 69,145,938
Deferred income tax benefit	(26,396,358)		(26,396,358)
Impairment of gas properties, net of tax	$ 42,704,056	$ 45,524	$ 42,749,580

For the nine months ended September 30, 2009, impairments recorded to gas properties were:

	United States	Canada	Total
Impairment of gas properties	$ 234,554,219	$ 1,886,296	$ 236,440,515
Deferred income tax benefit	(89,599,779)		(89,599,779)
Impairment of gas properties, net of tax	$ 144,954,440	$ 1,886,296	$ 146,840,736

Note 5 Asset Retirement Liability

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

The following table details the changes to our asset retirement liability for the nine months ended September 30, 2009:

Current portion of liability at January 1, 2009	$ 117,423
Add: Long-term asset retirement liability at January 1, 2009	4,348,938
Asset retirement liability at January 1, 2009	4,466,361
Liabilities incurred	11,996
Liabilities settled	(8,275)
Accretion	323,726
Foreign currency translation	26,802
Asset retirement liability at September 30, 2009	4,820,610
Less: Current portion of liability	(113,675)
Long-term asset retirement liability	$ 4,706,935

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

Note 6 Derivative Instruments and Hedging Activities

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

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 70% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu below the bought floor. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

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

Commodity Price Risk and Related Hedging Activities

At September 30, 2009, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
October 2009 (1)	186,000	(1)	$ 7.50	$ 5.25	$ 418,263
October 2009 (1)	186,000	(1)	$ 8.50	$ 6.50	371,790
October 2009 (1)	372,000	$ 4.50	$ 3.70	(1)	
November 2009 through March 2010	906,000	$ 11.20	$ 9.50	$ 7.00	2,075,011
November 2009 through March 2010	604,000	$ 6.65	$ 5.50	$ 3.50	117,151
April through October 2010	856,000	$ 6.80	$ 5.50	$ 3.50	(99,919)
April through October 2010	856,000	$ 6.35	$ 5.50		(176,250)
November 2010 through March 2011	604,000	$ 7.45	$ 6.50		(115,851)
					$ 2,590,195

(1) In connection with the July through October 2009 natural gas collar related to natural gas volumes of 1,476,000 MMBtu/day denoted above, the Company eliminated the existing $10.00 sold ceilings with respect to all three-way-collars through October 2009.

At September 30, 2009, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Price	Fair Value
October 2009	124,000	$ 4.47	$ 91,708
April through October 2010	856,000	$ 5.70	(336,760)
November 2010 through March 2011	604,000	$ 6.67	(237,497)
April 2011 through October 2011	856,000	$ 6.37	(188,493)
November 2011 through March 2012	608,000	$ 7.12	(124,627)
			$ (795,669)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under FASB ASC 815-20-25 (Prior authoritative literature: FASB Statement 133, Accounting for Derivative Instruments and Hedging Activities). Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At September 30, 2009, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate (1)	Notional amount	Fair Value
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%	$ 15,000,000	$ (560,232)
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%	$ 10,000,000	(173,760)
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%	$ 10,000,000	(96,452)
Floating-to-fixed swap	5/13/2008	5/13/2010	3.07%	$ 5,000,000	(94,617)
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	(36,497)
					$ (961,558)

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

For the three and nine months ended September 30, 2009, we have recognized no ineffective portion of our cash flow hedges. We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our revolving credit facility agreement and the collateral for the outstanding borrowings under our revolving credit facility agreement is used as collateral for our hedges. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our revolving credit facility agreement.

The application of FASB ASC 820-10-55 (Prior authoritative literature: FASB Statement 157, Fair Value Measurements), currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both at September 30, 2009. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

Natural Gas Hedges In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

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

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	September 30, 2009		December 31, 2008		September 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under ASC 815-20-25								
Interest rate swaps	Derivative asset (current)	$	Derivative asset (current)	$	Derivative liability (current)	$ 876,062	Derivative liability (current)	$ 714,903
Interest rate swaps	Derivative asset (non-current)	1,080	Derivative asset (non-current)		Derivative liability (non-current)	86,577	Derivative liability (non-current)	374,489
Total derivatives designated as hedging instruments under ASC 815-20-25		$ 1,080		$		$ 962,639		$ 1,089,392
Derivatives not designated as hedging instruments under ASC 815-20-25								
Natural gas collar positions	Derivative asset (current)	$ 2,805,483	Derivative asset (current)	$ 6,596,360	Derivative liability (current)	$	Derivative liability (current)	$
Natural gas collar positions	Derivative asset (non-current)		Derivative asset (non-current)	723,669	Derivative liability (non-current)	215,290	Derivative liability (non-current)	
Natural gas swap positions	Derivative asset (current)	(164,194)	Derivative asset (current)		Derivative liability (current)		Derivative liability (current)	

14

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

	Asset Derivatives				Liability Derivatives			
	September 30, 2009		December 31, 2008		September 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Natural gas swap positions	Derivative asset (non-current)		Derivative asset (non-current)		Derivative liability (non-current)	631,472	Derivative liability (non-current)	
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 2,641,289		$ 7,320,029		$ 846,762		$

The following (gains) losses on our hedging instruments included in the consolidated statements of operations and other comprehensive (loss) income (OCI) are as follows:

The Effect of Derivative Instruments on the Consolidated Statements of Operations and

Other Comprehensive (Loss) Income for the three and nine months ended September 30, 2009 and 2008

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative			
		Three months ended September 30,		Nine months ended September 30,	
		2009	2008	2009	2008
Derivatives designated as hedging instruments under ASC 815-20-25					
Interest rate swaps	Interest expense (net of amounts capitalized)	$ 310,113	$ 71,691	$ 778,646	$ 89,989
Total loss (gain)		$ 310,113	$ 71,691	$ 778,646	$ 89,989
Derivatives not designated as hedging instruments under ASC 815-20-25					
Natural gas collar positions	Realized (gains) losses on derivative contracts	$ (3,169,060)	$ 1,389,952	$ (8,626,180)	$ 2,021,188
Natural gas collar positions	Unrealized losses (gains) from the change in market value of open derivative contracts	3,567,270	(21,564,961)	5,525,502	(820,369)
Total loss (gain)		$ 398,210	$ (20,175,009)	$ (3,100,678)	$ 1,200,819

15

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships Interest Rate Swaps				
Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Interest expense			
Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)	$ (224,281)	$ (213,619)	$ (650,812)	$ (224,325)
Location of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Interest expense			
Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	$ (310,113)	$ (71,691)	$ (778,646)	$ (89,989)
	Other income/(expense)			
Amount of Gain or (Loss) Recognized in income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	$	$	$	$

Note 7 Long-Term Debt

On November 5, 2009, the Company s bank syndicate approved a borrowing base of $135 million after completing its mid-year borrowing base determination based on our internally prepared reserve report as of September 30, 2009. The next regular borrowing base determination, which will be based on a December 31, 2009 reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, is scheduled to be complete on or before June 15, 2010. Our revolving credit facility permits us to borrow and repay amounts as needed based on the available borrowing base as determined in the revolving credit facility agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. Except for the most recent borrowing base determination, the borrowing base under the revolving credit facility is based upon the reserve valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the bank syndicate, including Bank of America as agent. The bank syndicate may also request one additional borrowing base re-determination in any fiscal year. If not extended, our revolving credit facility will mature in January 2011.

As of September 30, 2009, we had $119.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $20.5 million under our $140.0 million borrowing base. For the three and nine months ended September 30, 2009 we borrowed $4.60 million and $33.15 million, respectively, and made payments of $6.85 million and $30.15 million, respectively, under the revolving credit facility. For the three and nine months ended September 30, 2008 we borrowed $38.50 million and $89.00 million, respectively, and made payments of $30.00 million and $77.00 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at the Company s option of either (a) the bank s adjusted base rate, which is the greatest of (i) the bank s base rate, (ii) the Federal Funds Rate plus 0.5%, or (iii) the one-month LIBOR rate plus 1%, plus a margin of 1.375% to 2.125% based on borrowing base usage, or (b) the adjusted LIBOR rate, plus a margin of 2.25% to 3.00%, based on borrowing base usage. The rates at September 30, 2009 and December 31, 2008, excluding the effect of our interest rate swaps, were 3.08% and 2.49%, respectively. For the three months ended September 30, 2009 and 2008, interest on the borrowings averaged 3.29% per annum and 4.35% per annum, respectively. For the nine months ended September 30, 2009 and 2008, interest on the borrowings averaged 3.09% per annum and 4.81% per annum, respectively.

The following is a summary of our long-term debt at September 30, 2009 and December 31, 2008:

	September 30, 2009	December 31, 2008
Borrowings under revolving credit facility	$ 119,500,000	$ 116,500,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	109,944	135,972
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	94,190	118,735
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	431,910	475,015

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

	September 30, 2009	December 31, 2008
Total debt	120,136,044	117,229,722
Less current maturities included in current liabilities	(120,090)	(111,767)
Total long-term debt	$ 120,015,954	$ 117,117,955

We are subject to certain restrictive covenants under the revolving credit facility agreement, including a minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability, of 1.0 to 1.0, and a ratio of consolidated EBITDA to interest expense of up to 2.75 to 1.0, both as defined in the revolving credit facility agreement. As of September 30, 2009, we were in compliance with all of the covenants in the revolving credit facility agreement.

The fair value of long-term debt at September 30, 2009 and December 31, 2008 was approximately $113,739,983 and $92,485,449, respectively. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the S&P credit rating of a comparable company to ours and the stated interest rates of the debt instruments included our long-term debt, both at September 30, 2009.

Note 8 Common Stock

At September 30, 2009 and December 31, 2008, there were 39,466,790 and 39,305,152 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. At September 30, 2009 and December 31, 2008, there were 318,414 and 401,075 shares of restricted stock, respectively, included in the aforementioned common stock outstanding. For the three and nine months ended September 30, 2009, no common stock was issued upon the exercise of stock options granted under our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. On March 23, 2009, we issued 166,668 shares of common stock to our independent directors representing 50% of their 2009 retainer. Additionally, for the three and nine months ended September 30, 2009, 1,256 and 4,624 shares of restricted stock, respectively, were forfeited. On June 15, 2009, 403 shares of common stock were purchased by us from a non-executive employee for the payment of $613 in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled.

For the three and nine months ended September 30, 2008, we issued no shares and 44,337 shares, respectively, of common stock upon the exercise of stock options granted under our 2005 Stock Option Plan. In March 2008, we issued 253,806 shares of restricted stock to employees of the Company and 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. In September 2008, we issued 46,694 shares of restricted stock to employees of the Company. The shares of common stock for our independent directors and the restricted stock were issued pursuant to our 2006 Long-Term Incentive Plan. Additionally, for the three and nine months ended September 30, 2008, 32,279 shares and 37,170 shares of restricted stock, respectively, were forfeited.

Note 9 Share-Based Awards

As of September 30, 2009, we have two stock-based award plans authorized, which include our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted our 2006 Long-Term Incentive Plan, although we will continue to issue shares of our common stock upon exercise of awards previously granted under the 2005 Stock Option Plan.

Our 2006 Long-Term Incentive Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares are reserved for grant under this plan, of which 2,124,728 remain available for issuance at September 30, 2009. The 2006 Long-Term Incentive Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interests of our employees and independent directors with the interests of our stockholders, and to closely link compensation with our performance. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance-based awards and options issued to directors. Performance-based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Performance-based awards issued to our directors vest immediately.

During the three months ended September 30, 2009, we recorded a compensation expense accrual of $203,038 which was allocated among lease operating expenses ($8,240), general and administrative expenses ($151,926), and capitalized to unevaluated gas properties ($42,873). During the nine months ended September 30, 2009, we recorded a compensation

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

expense accrual of $809,877 which was allocated among lease operating expenses ($45,044), general and administrative expenses ($616,236), and capitalized to gas properties ($148,598). The future compensation cost of all the outstanding awards is $1,257,583 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.24 years. The significant assumptions used in determining the compensation costs included an expected volatility of 56.10%, risk-free interest rate of 1.25%, an expected term of 4.5 years, forfeiture rates from 5% to 15%, and no expected dividends.

Incentive Stock Options

The table below summarizes incentive stock option activity for the nine months ended September 30, 2009:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2008	477,169	$ 8.09		
Granted	606,507	$ 0.72		
Exercised		$		
Transferred	(12,048)	$ 8.30		
Forfeited	(53,105)	$ 3.65		
Outstanding at September 30, 2009	1,018,523	$ 3.93	5.35	$ 586,006
Options exercisable at September 30, 2009	338,978	$ 8.53	3.55	$ 3,449

During the three months ended September 30, 2009, no incentive stock options were granted. During the nine months ended September 30, 2009, 606,507 incentive stock options were granted with a weighted average grant-date fair value of $200,147. No incentive stock options were exercised during the three and nine months ended September 30, 2009. The total intrinsic value of incentive stock options exercised during the nine months ended September 30, 2008 was $220,275. During the nine months ended September 30, 2008, no incentive stock options were granted.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the nine months ended September 30, 2009:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2008	1,280,087	$ 3.87		
Granted	114,012	$ 0.72		
Exercised		$		
Transferred	12,048	$ 8.30		
Forfeited	(5,387)	$ 13.00		

Outstanding at September 30, 2009	1,400,760	$ 3.61	3.82	$ 110,592
Options exercisable at September 30, 2009	1,114,196	$ 3.05	3.44	$

During the three months ended September 30, 2009, no non-qualified stock options were granted. During the nine months ended September 30, 2009, 114,012 non-qualified stock options were granted with a weighted average grant-date fair value of $38,192. During the three and nine months ended September 30, 2009, no non-qualified stock options were exercised. During the three and nine months ended September 30, 2008, no non-qualified stock options were exercised nor granted.

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the nine months ended September 30, 2009:

	Number of Shares	Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2008	401,075	$ 6.60
Forfeited	(4,624)	$ 6.58
Vested	(78,037)	$ 3.98
Non-vested restricted stock at September 30, 2009	318,414	$ 7.24

On March 24, 2009, 48,397 shares of restricted stock vested. The fair value of the shares that vested on that date was $31,458. On June 15, 2009, 19,900 shares of restricted stock vested. The fair value of the shares that vested on that date was $30,049. On September 19, 2009, 9,740 shares of restricted stock vested. The fair value of the shares that vested on that date was $14,902.

Note 10 Commitments and Contingencies

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

CNX Antitrust Action

We filed a complaint against CNX Gas Company LLC (CNX) and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX s position and corporate and financial interests. In December 2007, we filed an amended petition that restated with specificity our claims against CNX and Island Creek, and added Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as defendants. On June 3, 2009, the Court ruled on the demurrers to our claims that had been filed by CNX, denying CNX s demurrers with respect to four of our five state-law antitrust claims for monopolization and attempted monopolization and upholding only the demurrers to one antitrust theory and the claims under Virginia law for tortious interference. As a result of this ruling, we are proceeding to full discovery and moving towards a trial on the merits, seeking $385.6 million in actual damages, with the possibility for trebling of those damages under the statute, as well as injunctive relief to prevent CNX and the other defendants from continuing these alleged anticompetitive activities. Although we remain open to a commercially reasonable settlement, we intend to pursue discovery and trial in this matter.

Environmental and Regulatory

As of September 30, 2009, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Note 11 Income Taxes

Our effective tax rate differs from the federal statutory rate primarily due to net operating losses (NOL s) in Canada and certain states from which we are currently unable to benefit, as well as state income taxes. The deferred tax asset related to the Canadian and certain state NOL s are fully reserved because it is more likely than not that we will not use those NOL s to offset existing tax liabilities in future years. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to September 30, 2010. For tax reporting purposes, we have federal and state NOL s of approximately $94.5 million and $4.5 million, respectively, at September 30, 2009 that are available to reduce future taxable income. If not utilized, the federal carryforwards would begin to expire in 2022. Certain immaterial portions of the state NOL s will expire prior to 2022.

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(Unaudited)

Income tax expense for the three months ended September 30, 2009 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	(24,725,666)	34.0%	(885,764)	26.0%	(25,611,430)	33.6%
State income taxes net of federal benefit	(2,884,551)	4.0%		0.0%	(2,884,551)	3.8%
Valuation Allowance		0.0%	885,764	-26.0%	885,764	-1.1%
Nondeductible items and other	(176,129)	0.2%		0.0%	(176,129)	0.2%
Income tax (benefit) provision	(27,786,346)	38.2%		0.0%	(27,786,346)	36.5%

Income tax expense for the three months ended September 30, 2008 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	9,699,553	34.0%	(115,013)	26.0%	9,584,540	34.1%
State income taxes net of federal benefit	772,860	2.7%		0.0%	772,860	2.8%
Valuation Allowance	(3,686)	0.0%	115,013	-26.0%	111,327	0.4%
Nondeductible items and other	135,690	0.5%		0.0%	135,690	0.5%
Income tax (benefit) provision	10,604,417	37.2%		0.0%	10,604,417	37.8%

Income tax expense for the nine months ended September 30, 2009 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	(81,861,937)	34.0%	(1,710,641)	26.0%	(83,572,578)	33.8%
State income taxes net of federal benefit	(9,535,122)	4.0%		0.0%	(9,535,122)	3.9%
Valuation Allowance		0.0%	1,710,641	-26.0%	1,710,641	-0.7%
Nondeductible items and other	(497,750)	0.2%		0.0%	(497,750)	0.2%
Income tax (benefit) provision	(91,894,809)	38.2%		0.0%	(91,894,809)	37.2%

Income tax expense for the nine months ended September 30, 2008 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	7,375,801	34.0%	(362,839)	26.0%	7,012,962	34.6%
State income taxes net of federal benefit	390,041	1.8%		0.0%	390,041	1.9%

Valuation Allowance	122,429	0.6%	362,839	-26.0%	485,268	2.4%
Nondeductible items and other	246,973	1.1%		0.0%	246,973	1.2%
Income tax (benefit) provision	8,135,244	37.5%		0.0%	8,135,244	40.1%

Table of Contents

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

Statement Regarding Forward-Looking Information

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

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2008, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 13, 2009.

Overview

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of September 30, 2009, we control a total of approximately 202,000 net acres of coalbed methane and oil and gas development rights.

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

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

Impact of Current Credit Market Conditions and Decreasing Natural Gas Prices

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows, natural gas reserves and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Declining or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Although we intend to cure any non-compliance with covenants in our revolving credit facility in the event they occur, no assurance can be given that we will be able to cure such non-compliance. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a

21

Table of Contents

material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

At September 30, 2009, the carrying value of the Company s gas properties in the U.S. and Canada exceeded the full cost ceiling limitation by $71.2 million, net of income tax of $44.0 million, based upon a natural gas price of approximately $3.38 per Mcf in effect at that date. However, as allowed by the guidelines of the SEC, since gas prices have significantly increased subsequent to September 30, 2009, a recalculation of the ceiling limitation has been performed based upon a natural gas price of approximately $4.43 per Mcf in effect at October 30, 2009, adjusted for location differentials. The result of the recalculation was that the net book value of our full cost pool exceeded the ceiling limitation. Therefore, for the three months ended September 30, 2009, impairments recorded to gas properties were:

	United States	Canada	Total
Impairment of gas properties	$ 69,100,414	$ 45,524	$ 69,145,938
Deferred income tax benefit	(26,396,358)		(26,396,358)
Impairment of gas properties, net of tax	$ 42,704,056	$ 45,524	$ 42,749,580

For the nine months ended September 30, 2009, impairments recorded to gas properties were:

	United States	Canada	Total
Impairment of gas properties	$ 234,554,219	$ 1,886,296	$ 236,440,515
Deferred income tax benefit	(89,599,779)		(89,599,779)
Impairment of gas properties, net of tax	$ 144,954,440	$ 1,886,296	$ 146,840,736

Holding all factors constant other than natural gas prices, a 10% and 20% decline in the prices used at September 30, 2009 would have resulted in an additional ceiling test impairment of approximately $27.2 million and $54.4 million, respectively, of our full cost pool.

As part of the revisions designed by the SEC to modernize the oil and gas company reserve reporting requirements, effective at December 31, 2009, the economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used. The application of this methodology at December 31, 2009 could result in an additional write-down of the carrying value of the full cost pool.

We believe that we are taking the necessary actions to position ourselves to continue operations in the current credit and commodity market environment. We believe we are positioned to sustain operations in the current economic and commodity market environment with $0.8 million in cash and $13.7 million available under our revolving credit facility as of November 5, 2009, premium natural gas pricing due to the geographic location of our properties, natural gas hedges, and long-lived reserves with shallow Company-wide annual production decline rates.

Decrease in Proved Reserves at September 30, 2009

We have prepared estimates of GeoMet s proved natural gas reserves as of September 30, 2009. These estimates were prepared internally by our reserve engineer in accordance with SEC rules and regulations. We retained DeGolyer and MacNaughton, independent petroleum engineers (D&M), to perform an audit of our proved reserves at September 30, 2009. A copy of the D&M audit report dated November 5, 2009 is filed with this report as Exhibit 99.1.

Due in large part to continued under-performance in the Gurnee field, our proved reserves as of September 30, 2009 were reduced to 212.7 Bcf, a decrease of approximately 33% from proved reserves of 319.5 Bcf at December 31, 2008. Our proved reserves at September 30, 2009 were also impacted by lower natural gas prices and costs in 2009. We were able to limit the effect of lower natural gas prices through our ongoing cost reduction strategy, which we implemented in April 2009. Consequently, approximately 87% (or 88.2 Bcf) of our downward revision was performance related, substantially all from the Gurnee field, and approximately 13% (or 12.9 Bcf) is the result of lower natural gas prices and costs used in the calculation of our proved reserves at September 30, 2009. For additional information regarding our estimated proved natural gas reserves, see Other Information Selected Supplementary Financial and Operating Information on Gas Exploration, Development and Production Activities (Unaudited) included in Item 5 of this report.

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. Coalbed methane-producing natural gas reservoirs generally are characterized by an initial period of inclining production rates as pressure in the reservoir decreases, followed by declining production rates that vary depending upon reservoir characteristics and other factors. These decline rates, however, are commonly lower than what is generally experienced with non-coalbed methane wells.

Initial estimates of future production in the Gurnee field were generally consistent with comparable coalbed methane-producing natural gas reservoirs in the adjacent Black Warrior Basin, which produces from the same Pottsville coal formations directly across an anticline. However, the actual performance of our wells in the Gurnee field has not demonstrated the characteristic initial inclining production rates common to coalbed methane reservoirs. D&M lowered estimates of future production in the Gurnee field in connection with the preparation its reports on our proved reserves as of December 31, 2007 and December 31, 2008. Now that the portion of the field east of the Cahaba River is substantially developed, and based upon continued monitoring of production results of our wells there, we concluded that actual production results did not support, with reasonable certainty, prior estimates of future production for the Gurnee field. Consequently, we have further reduced estimates of future production, eliminating all projected inclines in current production rates (other than those wells that have clearly demonstrated actual inclines in production) and have projected future production rates based on the current production performance of individual wells in the field.

Trends

Our business is influenced by trends that affect the natural gas industry. In particular, declines in natural gas prices and recent economic trends have adversely affected our business, liquidity, results of operations and financial condition.

We expect to face continuing challenges resulting from weakness in the U.S. residential and commercial real estate markets and continuing mortgage, commercial loan and credit card delinquencies, investor concerns about the strength of the U.S. economy, unresolved issues with structured investment vehicles, ongoing deleveraging of financial institutions and hedge funds and dislocation in the inter-bank market. If significant, continued volatility, changes in interest rates, defaults, market liquidity, declines in equity values, and the strengthening or weakening of foreign currencies against the U.S. dollar, individually or in tandem, could have a material adverse effect on our liquidity, results of operations, financial condition or cash flows through realized losses, and impairments.

Beginning in April 2009, we began implementing countermeasures in response to the above referenced trends in order to enhance our ability to execute our business strategy. These countermeasures included reducing costs, increasing hedging to reduce exposure to volatile natural gas prices and limiting capital spending. We are evaluating additional measures in light of the current credit and commodity markets include selling assets, entering into joint venture agreements with industry partners to reduce our costs, or alternate forms of financing.

On July 9, 2009, the Company announced that it had engaged a divestment firm to market a 50% non-operated working interest in 147 wells in the eastern portion of its Pond Creek Field in West Virginia. By the time bids were due in mid-August, natural gas prices were at their lowest point in over seven years. Although we received a number of bids for this package, none were deemed acceptable. The offers did not represent a reasonable value for the property and a sale at these depressed natural gas prices would not have benefited the Company or allowed it to achieve its financial or liquidity goals. Dialogue with certain interested parties continues and the possibility of a sale continues to exist but appears unlikely in the current natural gas price environment.

Table of Contents

Although we currently have borrowing availability under our revolving credit facility, we are exploring various alternatives for additional financing for the Company in order to reduce our debt and provide additional capital for growth. These alternatives may include private or public offerings of debt or equity securities. The terms, timing and structure of any such financing will depend on several factors, including market conditions, execution risk, timing, possible dilution of existing shareholders and relative cost of the various financing alternatives. There can be no assurance that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

The natural gas industry is capital intensive. We make, and anticipate that we will continue to make, substantial capital expenditures in the exploration for, development and acquisition of natural gas reserves. Historically, our capital expenditures have been financed primarily with internally generated cash from operations, proceeds from bank borrowings, and industry joint venture arrangements. The continued availability of these capital sources depends upon a number of variables, including proved reserves, production from existing wells, the sales prices for natural gas, our ability to acquire, locate and produce new reserves, and events occurring within the global capital markets. Except for the existing revolving credit facility we have with our bank syndicate, we do not currently have any agreements for future financing and there can be no assurance as to the availability or terms of any such future financing.

Operational Developments

Pond Creek We connected 3 new wells to sales in the nine months ended September 30, 2009, giving us a total of 245 productive wells in the Pond Creek field. Net gas sales increased to 14.4 MMcf per day for the nine months ended September 30, 2009, as compared to 13.5 MMcf per day for the nine months ended September 30, 2008. We added a fifth gas-fired compressor at our Pond Creek #1 site became operational in August. In addition, we are currently installing a reverse osmosis unit in Pond Creek that will reduce the amount of produced water we truck to our disposal well. We expect these new facilities will enhance production and reduce costs. We do not plan to commence further drilling in Pond Creek until January 2010, although certain preparatory and site work for 2010 drilling has already begun. We have deferred the 20 well drilling program we planned to start in the Virginia portion of the field in the third quarter of 2009 due to capital constraints resulting from depressed gas prices.

Lasher No new wells were added to sales in the nine months ended September 30, 2009. Net gas sales averaged 0.2 MMcf per day from 18 wells for the nine months ended September 30, 2009. A pump station was constructed in the second quarter and put into operation allowing produced water to be delivered from a tank battery to the disposal well by pipeline instead of trucking and thereby reducing produced water disposal costs.

Gurnee No new wells were added to sales in the nine months ended September 30, 2009. Net gas sales decreased to 5.9 MMcf per day for the nine months ended September 30, 2009, as compared to 6.1 MMcf per day for the nine months ended September 30, 2008. We have no drilling scheduled in Gurnee in 2009. Also, coal mining activity in the Gurnee field, which has disrupted our production and added to our cost, has ended.

Garden City Our focus in the Garden City Chattanooga Shale prospect is directed at determining a viable solution to handle produced water. We will be evaluating the results of our reverse osmosis unit in Pond Creek to determine if this is an economical solution for Garden City as well. However, due to low gas prices and the high cost of trucking produced water we have temporarily shut in the Garden City test wells.

Peace River On December 31, 2008, we commenced production from eight wells at Peace River with net gas sales from those eight wells averaging 0.1 MMcf per day for the nine months ended September 30, 2009. We own a 50% working interest and operate the project which covers over 50,000 acres of Crown tenure. Four coreholes and twelve production wells have been drilled, targeting the Lower Cretaceous Gething coals. Average coal thickness over the acreage is 52 feet, and the average gas content is 400 cubic feet per ton.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires us to use our judgment to make estimates and assumptions that affect certain amounts reported in our financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Critical accounting policies are those accounting policies that involve judgment and uncertainties affecting the application of those policies and the likelihood that materially different amounts would be reported under different conditions or using differing assumptions. We periodically update our estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. There have been no significant changes to our critical accounting policies during the three and nine months ended September 30, 2009.

Table of Contents

Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and nine months ended September 30, 2009 and 2008. This table should be read in conjunction with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Gas sales	$ 6,393	$ 18,674	$ 22,684	$ 54,956
Lease operating expenses	$ 3,195	$ 3,475	$ 11,112	$ 10,867
Compression and transportation expenses	1,235	1,129	4,050	3,178
Production taxes	248	599	856	1,655
Total production expenses	$ 4,678	$ 5,203	$ 16,018	$ 15,700
Net sales volumes (MMcf)	1,901	1,821	5,690	5,548
Pond Creek field	1,318	1,252	3,920	3,698
Gurnee field	527	558	1,620	1,667
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 3.36	$ 10.26	$ 3.99	$ 9.91
Average natural gas sales price realized(1)	$ 5.03	$ 9.49	$ 5.50	$ 9.54
Lease operating expenses	$ 1.68	$ 1.91	$ 1.95	$ 1.96
Pond Creek field	$ 1.27	$ 1.46	$ 1.38	$ 1.53
Gurnee field	$ 2.30	$ 2.81	$ 2.74	$ 3.07
Compression and transportation expenses	$ 0.65	$ 0.62	$ 0.71	$ 0.57
Pond Creek field	$ 0.64	$ 0.65	$ 0.71	$ 0.62
Gurnee field	$ 0.50	$ 0.55	$ 0.56	$ 0.53
Production taxes	$ 0.13	$ 0.33	$ 0.15	$ 0.30
Pond Creek field	$ 0.11	$ 0.19	$ 0.12	$ 0.15
Gurnee field	$ 0.19	$ 0.64	$ 0.23	$ 0.60
Total production expenses	$ 2.46	$ 2.86	$ 2.81	$ 2.83
Pond Creek field	$ 2.02	$ 2.30	$ 2.21	$ 2.30
Gurnee field	$ 2.99	$ 4.00	$ 3.53	$ 4.20
Depreciation, depletion and amortization	$ 2.72	$ 1.39	$ 1.79	$ 1.35

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

Results of Operations

Three months ended September 30, 2009 compared with three months ended September 30, 2008

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

	Three Months Ended September 30,		
	2009	2008	Change
	(In thousands)		
Gas sales	$ 6,393	$ 18,674	-66%
Lease operating expenses	$ 3,195	$ 3,475	-8%

Compression expense	$ 921	$ 824	12%
Transportation expense	$ 314	$ 305	3%
Production taxes	$ 248	$ 599	-59%
Impairment of gas properties	$ 69,146	$	NM
Depreciation, depletion and amortization	$ 5,169	$ 2,524	NM

Table of Contents

	Three Months Ended September 30, 2009	2008	Change
	(In thousands)		
General and administrative	$ 1,853	$ 2,098	-12%
Realized (gains) losses on derivative contracts	$ (3,169)	$ 1,390	NM
Unrealized losses (gains) from the change in market value of open derivative contracts	$ 3,567	$ (21,565)	NM
Interest expense, net of amounts capitalized	$ 1,386	$ 1,118	24%
Income tax (benefit) expense	$ (27,786)	$ 10,604	NM

NM-Not Meaningful

Gas sales. Gas sales decreased by $12.28 million, or 66%, to $6.39 million compared to the prior year quarter. The decrease in gas sales was a result of significantly lower natural gas prices partially offset by increased production. Production increased 4% and average natural gas prices decreased 67%, excluding hedging transactions. The $12.28 million decrease in gas sales consisted of a $13.10 million decrease in prices, offset by a $0.82 million increase in production. The increase in production was principally attributable to increased current year production related to prior year development activities at our Pond Creek field and the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River field in December 2008, partially offset by decreased production in our Gurnee field in September due to three wells being shut in September 2009 while various fracturing techniques were being tested.

Lease operating expenses. Lease operating expenses decreased by $0.28 million, or 8%, to $3.20 million compared to the prior year quarter. The decrease in lease operating expenses consisted of a $0.43 million decrease in costs, offset by a $0.15 million increase in production. The $0.43 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009, partially offset by increased expenses related to the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River field in December 2008.

Compression expense. Compression expense increased by $0.10 million, or 12%, to $0.92 million compared to the prior year quarter. The $0.10 million increase was comprised of a $0.06 million increase in costs and a $0.04 increase in production. The $0.06 million increase in costs was primarily due to the commencement of gas sales in our Garden City, Lasher, and Peace River fields in 2008 combined with an increase in the rates for electricity used to power certain compressors at our Pond Creek field.

Transportation expense. Transportation expenses were flat at $0.31 in the current and prior year periods.

Production taxes. Production taxes decreased by $0.35 million, or 59%, to $0.25 million compared to the prior year quarter. The $0.35 million decrease in production taxes was primarily due to decreased natural gas sales caused by lower natural gas prices.

Impairment of gas properties. At the end of the third quarter of 2009, the carrying value of the Company s gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the prior year period.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $2.65 million to $5.17 million compared to the prior year quarter. The depreciation, depletion and amortization increase consisted of a $2.54 million increase in the depletion rate due to our ceiling write-downs incurred to-date and a $0.11 million increase in production.

General and administrative. General and administrative expenses decreased by $0.25 million, or 12%, to $1.85 million compared to the prior year quarter. The primary driver of the decrease in general and administrative expenses was our cost reduction strategy, which was implemented in April 2009, partially offset by lower capitalized overhead as a result of decreased drilling activities.

Realized (gains) losses on derivative contracts. Realized gains on derivative contracts were $3.17 million in the current quarter as compared to realized losses of $1.39 million in the prior year quarter. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlements paid to us from the contract counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts were $3.57 million in the current quarter as compared to unrealized gains of $21.57 million in the prior year quarter.

Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period.

Table of Contents

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.27 million to $1.39 million compared to the prior year quarter. The increase is due to a higher average outstanding debt balance in the current year period, partially offset by a lower average interest rate in the current year period. Additionally, the prior year included $0.12 million of capitalized interest for which there was no comparable capitalized interest in the current year period.

Income tax benefit (expense). Income tax benefit was $27.79 million in the current year period. The effective tax rate for the period was 36.5%. Income tax expense for the three months ended September 30, 2009 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	(24,725,666)	34.0%	(885,764)	26.0%	(25,611,430)	33.6%
State income taxes net of federal benefit	(2,884,551)	4.0%		0.0%	(2,884,551)	3.8%
Valuation Allowance		0.0%	885,764	-26.0%	885,764	-1.1%
Nondeductible items and other	(176,129)	0.2%		0.0%	(176,129)	0.2%
Income tax (benefit) provision	(27,786,346)	38.2%		0.0%	(27,786,346)	36.5%

Nine months ended September 30, 2009 compared with nine months ended September 30, 2008

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

	Nine months ended September 30, 2009	Nine months ended September 30, 2008	Change
	(In thousands)		
Gas sales	$ 22,684	$ 54,956	-59%
Lease operating expenses	$ 11,113	$ 10,867	2%
Compression expense	$ 2,703	$ 2,254	20%
Transportation expense	$ 1,347	$ 923	46%
Production taxes	$ 856	$ 1,655	-48%
Impairment of gas properties	$ 236,441	$	NM
Depreciation, depletion and amortization	$ 10,187	$ 7,472	36%
General and administrative	$ 7,006	$ 7,478	-6%
Realized (gains) losses on derivative contracts	$ (8,626)	$ 2,021	NM
Unrealized losses (gains) from the change in market value of open derivative contracts	$ 5,526	$ (820)	NM
Interest expense, net of amounts capitalized	$ (3,787)	$ (3,538)	7%
Income tax (benefit) expense	$ (91,895)	$ 8,135	NM

NM-Not Meaningful

Gas sales. Gas sales decreased by $32.27 million, or 59%, to $22.68 million compared to the prior year period. The decrease in gas sales was a result of significantly lower natural gas prices, which decreased 60% excluding hedging transactions, partially offset by increased production, which increased 3%.The $32.27 million decrease in gas sales consisted of a $33.68 million decrease in prices, offset by a $1.41 million increase in production. The increase in production was principally attributable to the prior year development activities at our Pond Creek field and the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River field in December 2008, partially offset by the sale of an overriding royalty interest that was sold effective July 1, 2008 and decreased current year production in our Gurnee field.

Lease operating expenses. Lease operating expenses increased by $0.25 million, or 2%, to $11.11 million compared to the prior year period. The increase in lease operating expenses consisted of a $0.03 million decrease in costs and a $0.28 million increase in production. The $0.41 increase in costs was primarily due to the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River field in December 2008, offset by a credit for prior period ad valorem taxes. Generally, lease operating expenses are higher in the early life of a prospect when fixed costs are spread over a small amount of sales volumes.

Table of Contents

Compression expense. Compression expense increased by $0.45 million, or 20%, to $2.70 million compared to the prior year period. The $0.45 million increase was comprised of a $0.39 million increase in costs and a $0.06 increase in production. The $0.39 increase in costs was primarily due to routine maintenance of some of the compressors in our Cahaba field and increased rates for electricity used to power compressors at our Pond Creek field, as well as unscheduled repair and maintenance costs.

Transportation expense. Transportation expenses increased by $0.42 million, or 46%, to $1.35 million compared to the prior year period. The increase in costs was primarily due to the fact that a greater amount of excess capacity was released in the prior year period effectively reducing transportation expense for that period. The excess transportation capacity that caused the increase was permanently released in May 2009. As a result of this permanent release, we expect to incur less transportation costs in the future.

Production taxes. Production taxes decreased by $0.80 million, or 48%, to $0.86 million compared to the prior year period. The $0.80 million decrease in production taxes was primarily due to decreased natural gas sales caused by lower natural gas prices.

Impairment of gas properties. At the end of the second and third quarters of 2009, the carrying value of the Company s gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the prior year period.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $2.72 million, or 36%, to $10.19 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of a $0.19 million increase in production and a $2.53 million increase in the depletion rate due to our ceiling write-downs incurred to-date.

General and administrative. General and administrative expenses decreased by $0.47 million, or 6%, to $7.01 million compared to the prior year period. The primary driver of the decrease in general and administrative expenses is the cost reduction strategy implemented in April 2009, partially offset by lower capitalized overhead as a result of decreased drilling activities.

Realized (gains) losses on derivative contracts. Realized gains on derivative contracts were $8.63 million in the current year period as compared to realized losses of $2.02 million in the prior year period. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlement paid to us from the contract counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts were $5.53 million in the current year period as compared to unrealized gains of $0.82 million in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.25 million to $3.79 million compared to the prior year period. The increase is due to the effect of a higher average outstanding debt balance in the current year period, partially offset by a lower average interest rate in the current year period. Additionally, the prior year included $0.30 million of capitalized interest for which there was no comparable capitalized interest in the current year period.

Income tax benefit. Income tax benefit was $91.90 million in the current year. The effective tax rate for the period was 37.2%. Income tax expense for the nine months ended September 30, 2009 was different than the amount computed using the statutory rate as follows:

	U.S.		**Canada**		**Total**	
Amount computed using statutory rates	(81,861,937)	34.0%	(1,710,641)	26.0%	(83,572,578)	33.8%
State income taxes net of federal benefit	(9,535,122)	4.0%		0.0%	(9,535,122)	3.9%
Valuation Allowance		0.0%	1,710,641	-26.0%	1,710,641	-0.7%
Nondeductible items and other	(497,750)	0.2%		0.0%	(497,750)	0.2%
Income tax (benefit) provision	(91,894,809)	38.2%		0.0%	(91,894,809)	37.2%

Table of Contents

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the nine months ended September 30, 2009 and 2008 were $6.9 million and $25.0 million, respectively. Cash flows from operations of $6.9 million for the nine months ended September 30, 2009, combined with net cash provided by financing activities of $2.9 million and the use of available cash, were sufficient to fund net cash used in investing activities of $11.1 million, which primarily includes capital expenditures for the exploration and development of our gas properties a significant portion of which was carryover costs from our 2008 program. Net cash provided by financing activities was related to revolving credit facility net borrowings.

As of September 30, 2009, we had a working capital deficit of approximately $2.5 million. As of December 31, 2008, we had a working capital deficit of approximately $1.4 million.

On November 5, 2009, the Company s bank syndicate approved a borrowing base of $135 million after completing its mid-year borrowing base determination. On that date, we had $121.3 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $13.7 million under our $135.0 million borrowing base.

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our revolving credit facility and proceeds from potential transactions such as equity offerings, joint ventures, or asset sales will provide the ability to develop our existing properties and conduct exploration.

Although we currently have borrowing availability under our revolving credit facility, we are exploring various alternatives for additional financing for the Company in order to reduce our debt and provide additional capital for growth. These alternatives may include private or public offerings of debt or equity securities. The terms, timing and structure of any such financing will depend on several factors, including market conditions, execution risk, timing, possible dilution of existing shareholders and relative cost of the various financing alternatives. There can be no assurance that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued declining or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

The recent disruption in the credit markets has had a significant adverse impact on a number of financial institutions. We have reviewed the creditworthiness of the banks and financial institutions with which we maintain our cash and short-term investments. Thus far, our liquidity and financial position have not been impacted. However, we cannot predict with any certainty the impact of any further disruption in the credit markets.

A prolonged period of declining or low natural gas prices may result in non-compliance with the covenants in our revolving credit facility agreement and could result in future lower borrowing base determinations. Our borrowing base was reduced from $180 million to $140 million in March 2009 and further reduced to $135 million in November 2009. These reductions in the borrowing base of our revolving credit facility were the result of changes in our proved natural gas reserve estimates, lower natural gas prices and uncertainty in the credit markets. Natural gas prices have recently been the lowest since 2002 and continue to be highly volatile; however, we have recently seen a seasonal increase in natural gas prices from the low levels reached in September 2009. Our ability to comply with the covenants in our revolving credit facility agreement and maintain an adequate level of borrowing base are affected by changes in our reserve estimates, natural gas prices and conditions in the credit markets. If we fail to comply with these covenants, it could lead to an event of default, the acceleration of repayment of outstanding debt and exercise of certain remedies by lenders, including foreclosure on our pledged properties. Based on our current borrowing base and our current projections, we expect to meet our liquidity needs and to comply with the covenants in our revolving credit facility agreement; however, as indicated above, if natural gas prices retreat to their low levels experienced earlier this year, we may not be able to comply with those covenants. We intend to cure or seek waivers for any non-compliance with the covenants in our revolving credit facility agreement; however, no assurance can be given that we will be able to cure or obtain waivers for such non-compliance.

Table of Contents

Price Risk Management Activities

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

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 70% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu below the bought floor. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

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

Commodity Price Risk and Related Hedging Activities

At September 30, 2009, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
October 2009 (1)	186,000	(1)	$ 7.50	$ 5.25	$ 418,263
October 2009 (1)	186,000	(1)	$ 8.50	$ 6.50	371,790
October 2009 (1)	372,000	$ 4.50	$ 3.70	(1)	
November 2009 through March 2010	906,000	$ 11.20	$ 9.50	$ 7.00	2,075,011
November 2009 through March 2010	604,000	$ 6.65	$ 5.50	$ 3.50	117,151
April through October 2010	856,000	$ 6.80	$ 5.50	$ 3.50	(99,919)
April through October 2010	856,000	$ 6.35	$ 5.50		(176,250)
November 2010 through March 2011	604,000	$ 7.45	$ 6.50		(115,851)
					$ 2,590,195

(1) In connection with the July through October 2009 natural gas collar related to natural gas volumes of 1,476,000 MMBtu/day denoted above, the Company eliminated the existing $10.00 sold ceilings with respect to all three-way-collars through October 2009.

At September 30, 2009, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Price	Fair Value
October 2009	124,000	$ 4.47	$ 91,708
April through October 2010	856,000	$ 5.70	(336,760)
November 2010 through March 2011	604,000	$ 6.67	(237,497)
April 2011 through October 2011	856,000	$ 6.37	(188,493)

November 2011 through March 2012	608,000	$ 7.12	(124,627)
			$ (795,669)

Table of Contents

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under ASC 815-20-25. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At September 30, 2009, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate (1)	Notional amount	Fair Value
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%	$ 15,000,000	$ (560,232)
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%	$ 10,000,000	(173,760)
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%	$ 10,000,000	(96,452)
Floating-to-fixed swap	5/13/2008	5/13/2010	3.07%	$ 5,000,000	(94,617)
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	(36,497)
					$ (961,558)

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

Capital Expenditures and Capital Resources

The following table is a summary of our capital expenditures on an accrual basis by category:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Capital expenditures:				
Leasehold acquisition	$ 132,270	$ 1,288,356	$ 1,087,887	$ 3,123,842
Exploration	3,720	143,060	25,597	399,695
Development	1,666,250	19,333,521	5,168,326	35,471,877
Other items (primarily capitalized overhead and interest)	439,376	1,228,787	1,449,686	4,162,014
Total capital expenditures	$ 2,241,616	$ 21,993,724	$ 7,731,496	$ 43,157,428

We expect our capital expenditure budget for 2009 to be funded from our operating cash flows. If the amount or timing of cash flows are reduced, we intend to reduce our capital spending accordingly. The amount and timing of our expenditures are subject to change based upon market conditions, natural gas prices, results of expenditures and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and changes in borrowing capacity under our revolving credit facility. We expect capital expenditures to be approximately $9.3 million in 2009.

The development of coalbed methane fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, the transportation alternatives, and the timing and rate of initial and subsequent natural gas production volumes.

There continues to be an unprecedented uncertainty in the financial markets. The uncertainty in the market brings additional potential risks to us. The risks include less availability and higher costs of additional credit, potential counterparty defaults, and further commercial bank failures. Although the financial institutions in our bank group appear to be capable of meeting their obligation under the facility, some that have been and others could be considered take-over candidates. Although we have no indication that any such transactions would impact our current revolving credit facility, the possibility exists. Financial market disruptions may impact our ability to collect trade receivables. We constantly monitor the credit worthiness of our customers. We believe that our current group of counterparties are sound and represent no abnormal business risk.

Table of Contents

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

Revolving Credit Facility

On November 5, 2009, the Company s bank syndicate approved a borrowing base of $135 million after completing its mid-year borrowing base determination based on our internally prepared reserve report as of September 30, 2009. The next regular borrowing base determination, which will be based on a December 31, 2009 reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, is scheduled to be complete on or before June 15, 2010. Our revolving credit facility permits us to borrow and repay amounts as needed based on the available borrowing base as determined in the revolving credit facility agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. Except for the most recent borrowing base determination, the borrowing base under the revolving credit facility is based upon the reserve valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the bank syndicate, including Bank of America as agent. The bank syndicate may also request one additional borrowing base re-determination in any fiscal year. If not extended, our revolving credit facility will mature in January 2011.

As of September 30, 2009, we had $119.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $20.5 million under our $140.0 million borrowing base. For the three and nine months ended September 30, 2009 we borrowed $4.60 million and $33.15 million, respectively, and made payments of $6.85 million and $30.15 million, respectively, under the revolving credit facility. For the three and nine months ended September 30, 2008 we borrowed $38.5 million and $89.0 million, respectively, and made payments of $30.0 million and $77.0 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at the Company s option of either (a) the bank s adjusted base rate, which is the greatest of (i) the bank s base rate, (ii) the Federal Funds Rate plus 0.5%, or (iii) the one-month LIBOR rate plus 1%, plus a margin of 1.375% to 2.125% based on borrowing base usage, or (b) the adjusted LIBOR rate, plus a margin of 2.25% to 3.00%, based on borrowing base usage. The rates at September 30, 2009 and December 31, 2008, excluding the effect of our interest rate swaps, were 3.08% and 2.49%, respectively. For the three months ended September 30, 2009 and 2008, interest on the borrowings averaged 3.29% per annum and 4.35% per annum, respectively. For the nine months ended September 30, 2009 and 2008, interest on the borrowings averaged 3.09% per annum and 4.81% per annum, respectively.

We are subject to certain restrictive covenants under the revolving credit facility agreement, including a minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability under the revolving credit agreement, of 1.0 to 1.0, and a ratio of consolidated EBITDA, as defined in the revolving credit facility agreement, to interest expense of up to 2.75 to 1.0, both as defined in the revolving credit facility agreement. As of September 30, 2009, we were in compliance with all of the covenants in the revolving credit facility agreement.

Contractual Commitments

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

Table of Contents

Recent Pronouncements

FASB Accounting Standards Codification In June 2009, the Financial Accounting Standards Board (FASB) issued ASC 105 (formerly SFAS 168), The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (ASC 105). ASC 105 has become the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernment entities. It also modifies the GAAP hierarchy to include only two levels of GAAP; authoritative and non-authoritative. The Company adopted ASC 105 effective July 1, 2009. Pursuant to the provisions of ASC 105, the Company has updated references to GAAP in its financial statements issued for the period ended September 30, 2009. The adoption of ASC 105 did not have an impact on the Company s financial position, results of operations or cash flows.

Fair Value Measurements and Disclosures In August 2009, the FASB issued Accounting Standards Update No. 2009-05 (ASC Update 2009-05), an update to ASC 820, Fair Value Measurements and Disclosures. This update provides amendments to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities. Among other provisions, this update provides clarification that in circumstances, in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the valuation techniques described in ASC Update 2009-05. ASC Update 2009-05 will become effective for the Company s annual financial statements for the year ended December 31, 2009. The adoption of ASC Update 2009-05 is not expected to have a material impact on the Company s financial position, results of operations or cash flows.

Subsequent Events In May 2009, the FASB issued FASB ASC 855-10-25 (Prior authoritative literature: FASB Statement 165, Subsequent Events). The standard does not require significant changes regarding recognition or disclosure of subsequent events, but does require disclosure of the date through which subsequent events have been evaluated for disclosure and recognition. The standard is effective for financial statements issued after June 15, 2009. The implementation of this standard did not have a significant impact on the financial statements of the Company. Subsequent events through the filing date of this Quarterly Report on Form 10-Q have been evaluated for disclosure and recognition.

Recent FASB Staff Positions On July 1, 2009, we adopted, effective for interim and annual periods ending after June 15, 2009:

(1) Determining Fair Value When Market Activity Has Decreased FASB ASC 820-10-65 (*Prior authoritative literature:* FASB Statement 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly)*, which applies to all assets and liabilities (i.e., financial and nonfinancial), reemphasizes that the objective of fair value remains unchanged (i.e., an exit price notion) ASC 820-10-65 provides application guidance on measuring fair value when the volume and level of activity has significantly decreased and identifying transactions that are not orderly. ASC 820-10-65 also emphasizes that an entity cannot presume that an observable transaction price is not orderly even when there has been a significant decline in the volume and level of activity. ASC 820-10-65 also requires enhanced disclosures.

(2) Other-Than-Temporary Impairment (OTTI) FASB ASC 320-10-65 (Prior authoritative literature: FASB FSP 115-2/124-2, Recognition and Presentation of Other-Than-Temporary Impairments) provides a new OTTI model for debt securities only. Equity securities will continue to apply the existing OTTI model. The FSP shifts the focus for debt securities from an entity s intent to hold until recovery to its intent to sell. ASC 320-10-65 also requires entities to initially apply the provisions of the standard to certain previously other-than-temporarily impaired debt instruments existing as of the date of initial adoption by making a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The cumulative-effect adjustment reclassifies the noncredit portion of a previously other-than-temporarily impaired debt security held as of the date of initial adoption from retained earnings to accumulated other comprehensive income. ASC 320-10-65 also requires enhanced disclosures.

(3) Interim Fair Value Disclosures for Financial Instruments FASB ASC 270-10-05 (Prior authoritative literature: APB 28-1, Interim Disclosures About Fair Value of Financial Instruments) expands the fair value disclosures required for all financial instruments within the scope of FASB ASC 825-10-50 (Prior authoritative literature: FASB Statement 107, Disclosures About Fair Value of Financial Instruments) to interim periods. The disclosure requirements of ASC 270-10-05 only apply to public entities. ASC 270-10-05 does not require interim disclosures of credit or market risks also discussed in FASB ASC 825-10-50.

The adoption of the aforementioned three FASB Staff Positions had no material impact on Consolidated Financial Statements (Unaudited) or the accompanying Notes to Consolidated Financial Statements (Unaudited).

Table of Contents

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

Commodity Prices Economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used. Therefore, an entity will no longer be able to perform a ceiling limitation test using natural gas prices in effect at a date subsequent to the balance sheet date but prior to the issuance of the consolidated financial statements if there is a significant increase in natural gas prices.

Disclosure of Unproved Reserves Probable and possible reserves may be disclosed separately on a voluntary basis.

Proved Undeveloped Reserve Guidelines Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.

Reserve Estimation Using New Technologies Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Reserve Personnel and Estimation Process Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

Non-Traditional Resources The definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. We are currently evaluating the new rules and assessing the impact they will have on our reported proved natural gas reserves. The SEC is coordinating with the FASB to obtain the revisions necessary to ASC 932 (Prior authoritative literature: FASB Statement 69, Disclosures About Oil and Gas Producing Activities an amendment of FASB Statements No. 19, 25, 33, and 39) to provide consistency with the new rules.

In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC will consider delaying the compliance date.

On October 29, 2009, the SEC released Staff Accounting Bulletin No. 113 (SAB 113). SAB 113 revises or rescinds portions of the interpretive guidance included in the section of the Staff Accounting Bulletin Series titled Topic 12: Oil and Gas Producing Activities (Topic 12) and revises a technical reference in Topic 3: Senior Securities (Topic 3). This update is intended to make the relevant interpretive guidance consistent with current authoritative accounting and auditing guidance and Commission rules and regulations. The principal changes involve revision or removal of material due to recent Commission rulemaking. Specifically, the staff is updating the Series in order to bring existing guidance into conformity with Modernization of Oil and Gas Reporting rules, issued December 31, 2008. SAB 113 also updates related interpretive responses and examples in Topic 12. The staff expects registrants to apply the updated guidance in SAB 113 related to Topic 12 on a prospective basis effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The impact on the Company will be that the Company will no longer be able to perform a ceiling limitation test using natural gas prices in effect at a date subsequent to the balance sheet date but prior to the issuance of the consolidated financial statements if there is a significant increase in natural gas prices.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are natural gas prices per Mcf in effect, adjusted for location differentials. Prices received for natural gas are volatile and unpredictable and are beyond our control. At September 30, 2009, a 10% decrease in the prices received for natural gas production would have had an approximate $3.4 million impact on our revenues.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. At September 30, 2009, we had $119.5 million outstanding under our revolving credit facility. At September 30, 2009 the average interest rate for the outstanding amount of the revolving credit facility was 3.08% per annum, respectively. Borrowing availability at September 30, 2009 was $20.5 million. All of the debt outstanding under our revolving credit facility accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance outstanding under our revolving credit facility at September 30, 2009, a 1% increase in

Table of Contents

market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.8 million. $45 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swaps we have in place.

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Based on the evaluation of our disclosure controls and procedures by our Chief Executive Officer and Chief Financial Officer, as of the end of the period covered by this quarterly report, each of them has concluded that our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, are effective.

Changes in Internal Controls Over Financial Reporting

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

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

CNX Antitrust Action

We filed a complaint against CNX Gas Company LLC (CNX) and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX s position and corporate and financial interests. In December 2007, we filed an amended petition that restated with specificity our claims against CNX and Island Creek, and added Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as defendants. On June 3, 2009, the Court ruled on the demurrers to our claims that had been filed by CNX, denying CNX s demurrers with respect to four of our five state-law antitrust claims for monopolization and attempted monopolization and upholding only the demurrers to one antitrust theory and the claims under Virginia law for tortious interference. As a result of this ruling, we are proceeding to full discovery and moving towards a trial on the merits, seeking $385.6 million in actual damages, with the possibility for trebling of those damages under the statute, as well as injunctive relief to prevent CNX and the other defendants from continuing these alleged anticompetitive activities. Although we remain open to a commercially reasonable settlement, we intend to pursue discovery and trial in this matter.

Environmental and Regulatory

As of September 30, 2009, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Table of Contents

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009, or our Annual Report on Form 10-K for the year ended December 31, 2008.

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

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information - Selected Supplementary Financial and Operating Information on Gas Exploration, Development and Production Activities (Unaudited)

These selected supplemental schedules provide selected unaudited information selected from annual disclosure requirements pursuant to ASC 932 (Prior authoritative literature: FASB Statement 69, Disclosures About Oil and Gas Producing Activities an amendment of FASB Statements No. 19, 25, 33, and 39) and certain other information.

Capitalized Costs Capitalized costs and accumulated depreciation, depletion, amortization and impairment of gas properties relating to our gas producing activities, all of which are conducted within the continental U.S. and Canada, at September 30, 2009 and December 31, 2008, 2007 and 2006 are summarized below.

We capitalize certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of our investment in natural gas properties over the periods benefited by these activities. During the nine months ended September 30, 2009 and the years ended December 31, 2008, 2007 and 2006, these capitalized costs amounted to $1,226,982, $2,329,748, $1,991,760 and $1,174,148, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. Capitalized costs in 2007 include a $3.0 million purchase price adjustment for a 2004 acquisition. For the nine months ended September 30, 2009 no interest costs were capitalized. For the years ended December 31, 2008, 2007 and 2006, interest costs of $304,342, $587,884 and $1,037,576, respectively, were capitalized.

	September 30, 2009	December 31, 2008	2007	2006
Unevaluated properties U.S.	$	$ 5,017	$ 6,651,594	$ 13,680,374
Unevaluated properties Canada			18,523,170	12,717,608
Properties subject to amortization U.S.	432,620,791	425,437,272	370,404,336	310,011,154
Properties subject to amortization Canada	25,923,616	22,531,264		
Capitalized costs consolidated	458,544,407	447,973,553	395,579,100	336,409,136
Accumulated depreciation, depletion, amortization and impairment of gas properties U.S.	(314,238,765)	(72,743,290)	(30,661,248)	(21,836,904)
Accumulated depreciation, depletion, amortization and impairment of gas	(25,923,616)	(18,686,273)		

properties Canada					
Net capitalized costs consolidated		118,382,026	356,543,990	364,917,852	314,572,232
Net capitalized costs Canada			3,844,991	18,523,170	12,717,608
Net capitalized costs U.S.		118,382,026	352,698,999	343,394,682	301,854,624
Net capitalized costs consolidated	$	118,382,026	$ 356,543,990	$ 364,917,852	$ 314,572,232

Table of Contents

Capitalized Costs Incurred

The following table discloses costs incurred in gas property acquisition, exploration and development activities for the nine months ended September 30, 2009 and the years ended December 31, 2008, 2007 and 2006.

	January 1, 2009 Through September 30, 2009	For the Years Ended December 31, 2008	2007	2006
Acquisition costs-proved U.S.	$ 2,258,065	$ 3,153,568	$ 3,827,641	$ 428,729
Acquisition costs-unproved U.S.		2,779,865	4,883,982	9,113,502
Exploration costs incurred U.S.	25,597	6,055,041	1,937,858	2,559,745
Development costs incurred U.S.	4,894,840	34,670,459	42,561,606	62,654,438
Total costs incurred U.S.	7,178,502	46,658,933	53,211,087	74,756,414
Acquisition costs-proved Canada	56,804	65,251		
Acquisition costs-unproved Canada			435,133	1,717,097
Exploration costs incurred Canada		51,542	5,523,744	5,119,289
Development costs incurred Canada	3,335,548	5,618,726		
Total costs incurred Canada	3,392,352	5,735,519	5,958,877	6,836,386
Total costs incurred consolidated	$ 10,570,854	$ 52,394,452	$ 59,169,964	$ 81,592,800

Reserves The following table summarizes our net ownership interests in estimated quantities of proved gas reserves and changes in net proved reserves, all of which are located in the continental U.S. Reserve estimates of natural gas as of September 30, 2009 presented below were prepared by the Company s reserves engineer and audited by DeGolyer and MacNaughton, independent petroleum engineers. Reserve estimates of natural gas for all other periods presented below were prepared by DeGolyer and MacNaughton, independent petroleum engineers.

Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

	January 1, 2009 Through September 30, 2009	2008	2007	2006
Natural Gas Reserves (Mcf) U.S.				
Proved reserves at beginning of year	315,711,000	350,176,000	325,663,000	262,512,000
Revisions of previous estimates	(97,360,000)	(42,708,000)	(15,343,000)	28,417,000
Extensions and discoveries		17,613,000	46,982,000	39,138,000
Acquisition				1,824,000
Disposition		(1,917,000)		
Production	(5,662,000)	(7,453,000)	(7,126,000)	(6,228,000)
Proved reserves at end of year	212,689,000	315,711,000	350,176,000	325,663,000
Proved developed reserves at beginning of year	242,518,000	266,943,000	242,918,000	195,139,000

Proved developed reserves at end of year	165,105,000	242,518,000	266,943,000	242,918,000

	January 1, 2009 Through September 30, 2009	2008	2007	2006
Natural Gas Reserves (Mcf) Canada				
Proved reserves at beginning of year	3,818,000			
Revisions of previous estimates	(3,790,000)			
Extensions and discoveries		3,818,000		
Acquisition				
Disposition				
Production	(28,000)			
Proved reserves at end of year		3,818,000		
Proved developed reserves at beginning of year	3,818,000			
Proved developed reserves at end of year		3,818,000		

We have prepared estimates of GeoMet s proved natural gas reserves as of September 30, 2009. These estimates were prepared internally by our reserve engineer in accordance with SEC rules and regulations. We retained DeGolyer and MacNaughton, independent petroleum engineers (D&M), to perform an audit of our proved reserves at September 30, 2009. A copy of the D&M audit report dated November 5, 2009 is filed with this report as Exhibit 99.1.

Due in large part to continued under-performance in the Gurnee field, our proved reserves as of September 30, 2009 were reduced to 212.7 Bcf, a decrease of approximately 33% from proved reserves of 319.5 Bcf at December 31, 2008. Our proved reserves at September 30, 2009 were also impacted by lower natural gas prices and costs in 2009. We were able to limit the effect of lower natural gas prices through our ongoing cost reduction strategy, which we implemented in April 2009. Consequently, approximately 87% (or 88.2 Bcf) of our downward revision was performance related, substantially all from the Gurnee field, and approximately 13% (or 12.9 Bcf) is the result of lower natural gas prices and costs used in the calculation of our proved reserves at September 30, 2009.

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. Coalbed methane-producing natural gas reservoirs generally are characterized by an initial period of inclining production rates as pressure in the reservoir decreases, followed by declining production rates that vary depending upon reservoir characteristics and other factors. These decline rates, however, are commonly lower than what is generally experienced with non-coalbed methane wells.

Initial estimates of future production in the Gurnee field were generally consistent with comparable coalbed methane-producing natural gas reservoirs in the adjacent Black Warrior Basin, which produces from the same Pottsville coal formations directly across an anticline. However, the actual performance of our wells in the Gurnee field has not demonstrated the characteristic initial inclining production rates common to coalbed methane resevoirs. D&M lowered estimates of future production in the Gurnee field in connection with the preparation its reports on our proved reserves as of December 31, 2007 and December 31, 2008. Now that the portion of the field east of the Cahaba River is substantially developed, and based upon continued monitoring of production results of our wells there, we concluded that actual production results did not support, with reasonable certainty, prior estimates of future production for the Gurnee field. Consequently, we have further reduced estimates of future production, eliminating all projected inclines in current production rates (other than those wells that have clearly demonstrated actual inclines in production) and have projected future production rates based on the current production performance of individual wells in the field.

The following table presents the standardized measure of future net cash flows related to proved gas reserves in accordance with ASC 932. All components of the standardized measure are from proved reserves, all of which are located entirely within the continental U.S. and Canada. As prescribed by this statement, the amounts shown for September 30, 2009 are based on prices at October 29, 2009 and costs at September 30, 2009 and assume continuation of existing economic conditions. The amounts shown for December 31, 2008, 2007 and 2006 are based on prices and costs at December 31, 2008, 2007 and 2006 and assume continuation of existing economic conditions. Future income taxes are based on year-end statutory rates, adjusted for tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. Extensive judgments are involved in estimating the timing of future production and the costs that will be incurred throughout the remaining lives of the fields. Accordingly, the estimates of future net revenues from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do not remain static, and no price or cost changes have been considered, and future production and development costs are estimated to be incurred in developing and producing the estimated proved gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other gas producers.

Standardized Measure U.S.	September 30, 2009	2008	December 31, 2007	2006
Future cash inflows	$ 944,920,000	$ 1,844,199,000	$ 2,654,214,000	$ 1,858,104,000
Future production costs	(443,251,000)	(727,785,000)	(725,272,000)	(501,955,000)
Future development costs	(70,063,000)	(105,707,000)	(106,356,000)	(101,777,000)
Future income taxes	(72,914,000)	(290,341,000)	(602,319,000)	(410,391,000)
Future net cash flows	358,692,000	720,366,000	1,220,267,000	843,981,000
10% annual discount to reflect timing of cash flows	(239,407,000)	(413,859,000)	(724,399,000)	(484,494,000)
Standardized measure of discounted future net cash flows	$ 119,285,000	$ 306,507,000	$ 495,868,000	$ 359,487,000

Standardized Measure Canada	September 30, 2009	2008	December 31, 2007	2006
Future cash inflows	$	$ 20,932,000	$	$
Future production costs		(7,126,000)		
Future development costs		(30,000)		
Future income taxes				
Future net cash flows		13,776,000		
10% annual discount to reflect timing of cash flows		(9,936,000)		
Standardized measure of discounted future net cash flows	$	$ 3,840,000	$	$

Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2008, 2007 and 2006 are summarized below:

Changes in Standardized Measure	January 1, 2009 Through September 30, 2009	2008	2007	2006
Standardized measure at beginning of year	$ 310,347,000	$ 495,868,000	$ 359,487,000	$ 632,665,000
Sales and transfers of oil and gas produced net of production cost	(6,666,000)	(46,908,000)	(29,340,000)	(27,705,000)
Net changes in prices and production cost	(132,754,000)	(238,413,000)	248,627,000	(412,865,000)
Extensions and discoveries		17,666,000	58,936,000	63,721,000
Acquisition/disposition (net)		(9,708,000)		1,278,000
Net change in development cost	27,241,000	19,685,000	(43,181,000)	(4,187,000)
Revision of previous quantity estimates	(81,962,000)	(55,087,000)	(35,222,000)	49,362,000
Accretion of discount before income taxes	35,195,000	66,281,000	52,563,000	88,015,000
Net change in income taxes	41,601,000	125,336,000	(8,678,000)	81,343,000
Changes in production rates (timing) and other	(73,717,000)	(64,373,000)	(107,324,000)	(112,140,000)
Subtotal net change	(191,062,000)	(185,521,000)	136,381,000	(273,178,000)
Standardized measure at end of year	$ 119,285,000	$ 310,347,000	$ 495,868,000	$ 359,487,000

Table of Contents

The above tables were calculated using natural gas prices in effect as of the balance sheet date, adjusted for location differentials, held constant over the life of the reserves. The natural gas prices used at December 31, 2008, 2007 and 2006 were $5.84, $7.58 and $5.63 per Mcf, respectively. The natural gas prices used in the valuation of natural gas reserves at September 30, 2009 was the natural gas prices in effect as of October 30, 2009, adjusted for location differentials, which was $4.43 per mcf.

Holding all factors constant other than natural gas prices, a change in the price received for natural gas sales are estimated by us to result in the following:

Event	Increase (Decrease) in Reserves (Mcf)	Increase (Decrease) in Standardized Measure ($)
20% Increase In Natural Gas Price	5,329	47,115
20% Decrease In Natural Gas Price	(15,622)	(42,653)

Item 6. Exhibits

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

38

Table of Contents

SIGNATURES

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

	GeoMet, Inc.	
Date: November 12, 2009	By	/s/ William C. Rankin **William C. Rankin,**
		Executive Vice President and Chief Financial Officer
		(Principal Financial Officer)

Table of Contents

INDEX TO EXHIBITS

Exhibit Number	Exhibits
23.1*	Consent of Independent Petroleum Engineers DeGolyer and MacNaughton.
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).
99.1*	Audit Report of DeGolyer and MacNaughton.

* Filed herewith