CONTANGO OIL & GAS CO
Form 10-Q
May 09, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2012

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 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE	**95-4079863**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**

3700 BUFFALO SPEEDWAY, SUITE 960 HOUSTON, TEXAS 77098

(Address of principal executive offices)

(713) 960-1901

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 x 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. (Check one):

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

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

The total number of shares of common stock, par value $0.04 per share, outstanding as of April 30, 2012 was 15,357,166.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE NINE MONTHS ENDED MARCH 31, 2012

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All references in this Form 10-Q to the Company , Contango , we , us or our are to Contango Oil & Gas Company and its wholly-owned subsidiaries. Unless otherwise noted, all information in this Form 10-Q relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

ASSETS

	March 31, 2012	June 30, 2011
	(thousands)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 159,902	$ 150,007
Accounts receivable:		
Trade receivables	33,944	43,967
Joint interest billings	4,187	6,818
Income taxes		94
Other receivables	1,220	978
Other	4,144	3,014
Total current assets	203,397	204,878
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	563,409	552,556
Unproved properties	7,352	7,625
Furniture and equipment	200	227
Accumulated depreciation, depletion and amortization	(165,389)	(129,702)
Total property, plant and equipment, net	405,572	430,706
OTHER ASSETS:		
Investment in affiliates	12,169	935
Other	318	411
Total other assets	12,487	1,346
TOTAL ASSETS	$ 621,456	$ 636,930

The accompanying notes are an integral part of these consolidated financial statements.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

LIABILITIES AND SHAREHOLDERS EQUITY

	March 31, 2012	June 30, 2011
	(thousands, except share amounts)	
CURRENT LIABILITIES:		
Accounts payable	$ 3,668	$ 11,857
Royalties and revenue payable	23,821	39,222
Accrued liabilities	6,678	9,745
Accrued exploration and development		6,002
Income tax payable	270	6,942
Other current liabilities		4,456
Total current liabilities	34,437	78,224
DEFERRED TAX LIABILITY	120,575	123,472
ASSET RETIREMENT OBLIGATION	8,021	8,611
SHAREHOLDERS EQUITY:		
Common stock, $0.04 par value, 50,000,000 shares authorized; 20,135,107 shares issued and 15,357,166 outstanding at March 31, 2012; 20,135,107 shares issued and 15,664,666 outstanding at June 30, 2011	805	805
Additional paid-in capital	79,024	79,278
Treasury shares at cost (4,777,941 shares at March 31, 2012 and 4,470,441 shares at June 30, 2011)	(108,788)	(91,788)
Retained earnings	487,382	438,328
Total shareholders equity	458,423	426,623
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$ 621,456	$ 636,930

The accompanying notes are an integral part of these consolidated financial statements.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Nine Months Ended March 31, 2012	Nine Months Ended March 31, 2011
	(thousands, except per share amounts)			
REVENUES:				
Natural gas, oil and liquids sales	$ 41,339	$ 51,805	$ 139,449	$ 153,138
Total revenues	41,339	51,805	139,449	153,138
EXPENSES:				
Operating expenses	5,727	5,652	18,626	15,926
Exploration expenses	76	14	133	9,848
Depreciation, depletion and amortization	11,710	13,007	36,203	40,709
Impairment of natural gas and oil properties		1,675		1,786
General and administrative expenses	1,226	5,661	5,778	11,940
Total expenses	18,739	26,009	60,740	80,209
OTHER INCOME (EXPENSE)	42	(37)	(86)	(122)
NET INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	22,642	25,759	78,623	72,807
Provision for income taxes	(7,942)	(9,118)	(28,748)	(26,441)
NET INCOME FROM CONTINUING OPERATIONS	14,700	16,641	49,875	46,366
DISCONTINUED OPERATIONS (NOTE 7)				
Discontinued operations, net of income taxes	(26)	156	(821)	1,139
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 14,674	$ 16,797	$ 49,054	$ 47,505
NET INCOME PER SHARE:				
Basic				
Continuing operations	$ 0.96	$ 1.06	$ 3.23	$ 2.96
Discontinued operations	(0.00)	0.01	(0.05)	0.07
Total	$ 0.96	$ 1.07	$ 3.18	$ 3.03
Diluted				
Continuing operations	$ 0.96	$ 1.06	$ 3.23	$ 2.95
Discontinued operations	(0.00)	0.01	(0.05)	0.07
Total	$ 0.96	$ 1.07	$ 3.18	$ 3.02
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	15,357	15,665	15,453	15,665
Diluted	15,360	15,667	15,456	15,729

The accompanying notes are an integral part of these consolidated financial statements.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended March 31, 2012	Nine Months Ended March 31, 2011
	(thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Income from continuing operations	$ 49,875	$ 46,366
Income (loss) from discontinued operations, net of income taxes	(821)	1,139
Net income	49,054	47,505
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	36,203	46,980
Impairment of natural gas and oil properties	1,031	1,786
Exploration expenses		10,159
Deferred income taxes	(3,151)	(1,764)
Loss (gain) on sale of assets	169	(2,738)
Tax benefit from exercise/cancellation of stock options	(254)	(502)
Stock-based compensation	3	1,370
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable and other	10,023	(2,976)
Decrease (increase) in prepaids and other receivables	(1,750)	1,522
Decrease in accounts payable	(24,954)	(21,994)
Increase (decrease) in other accrued liabilities	(3,067)	7,761
Increase (decrease) in income taxes payable, net	(6,578)	6,887
Other	(85)	142
Net cash provided by operating activities	56,644	94,138
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	(18,734)	(55,155)
Additions to furniture and equipment	(35)	(72)
Repayment of note receivable	500	2,028
Advances under note receivable	(500)	
Investment in affiliates	(11,234)	(3,600)
Net cash used in investing activities	(30,003)	(56,799)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Dividends		(6)
Purchase of common stock	(17,000)	(9,769)
Tax benefit from exercise/cancellation of stock options	254	502
Debt issuance costs		(475)
Net cash used in financing activities	(16,746)	(9,748)
NET INCREASE IN CASH AND CASH EQUIVALENTS	9,895	27,591
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	150,007	52,469
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 159,902	$ 80,060

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for taxes, net of cash received	$ 38,035	$ 27,648
Cash paid for interest	$ 113	$ 123

The accompanying notes are an integral part of these consolidated financial statements.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS EQUITY

(Unaudited)

	Common Stock		Additional			Total
	Shares	Amount	Paid-in Capital	Treasury Stock	Retained Earnings	Shareholders Equity
			(thousands)			
Balance at June 30, 2011	15,665	$ 805	$ 79,278	$ (91,788)	$ 438,328	$ 426,623
Treasury shares at cost	(244)			(13,532)		(13,532)
Net income					14,904	14,904
Balance at September 30, 2011	15,421	$ 805	$ 79,278	$ (105,320)	$ 453,232	$ 427,995
Treasury shares at cost	(64)			(3,468)		(3,468)
Net income					19,476	19,476
Balance at December 31, 2011	15,357	$ 805	$ 79,278	$ (108,788)	$ 472,708	$ 444,003
Tax benefit from exercise of stock options			(254)			(254)
Net income					14,674	14,674
Balance at March 31, 2012	15,357	$ 805	$ 79,024	$ (108,788)	$ 487,382	$ 458,423

The accompanying notes are an integral part of these consolidated financial statements.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (GAAP) for interim financial information, pursuant to the rules and regulations of the Securities and Exchange Commission (SEC), including instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements. In the opinion of management, all adjustments considered necessary for a fair statement of the unaudited consolidated financial statements have been included. All such adjustments are of a normal recurring nature. The consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in Contango Oil & Gas Company s (Contango or the Company) Form 10-K for the fiscal year ended June 30, 2011. The consolidated results of operations for the three and nine months ended March 31, 2012 are not necessarily indicative of the results that may be expected for the fiscal year ending June 30, 2012.

2. Summary of Significant Accounting Policies

The application of GAAP involves certain assumptions, judgments, choices and estimates that affect reported amounts of assets, liabilities, revenues and expenses. Actual results could differ from these estimates. Contango s significant accounting policies are described below.

Successful Efforts Method of Accounting. The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. The provision for depreciation, depletion and amortization is based on the capitalized costs as determined above. Depreciation, depletion and amortization is on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves.

When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future net cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company s estimate of future natural gas and oil prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. No impairment of proved properties was recognized in continuing operations for the three or nine months ended March 31, 2012 and 2011. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. No impairment of unproved properties was recognized during the three or nine months ended March 31, 2012. For the three and nine months ended March 31, 2011, the Company recognized an impairment charge of approximately $1.7 million and $1.8 million, respectively, related to certain offshore leases.

Cash Equivalents. Cash equivalents are considered to be highly liquid investment grade investments having an original maturity of 90 days or less. As of March 31, 2012, the Company had approximately $159.9 million in cash and cash equivalents, all of which is held in non-interest bearing accounts.

Principles of Consolidation. The Company s consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries and affiliates, after elimination of all significant intercompany balances and transactions. Wholly-owned subsidiaries are consolidated. Exploration and development affiliates not wholly owned, such as 32.3% owned Republic Exploration, LLC (REX), are not controlled by the Company and are proportionately consolidated in the Company s financial statements.

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Stock-Based Compensation. The Company applies the fair value method of accounting for stock-based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the award vesting period. The Company classifies the benefits of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows. The fair value of each award is estimated using the Black-Scholes option-pricing model.

The Company s 1999 Stock Incentive Plan expired in August 2009 with the final 45,000 outstanding options issued under the plan exercised in February 2012. On September 15, 2009, the Company s Board of Directors adopted the Contango Oil & Gas Company Annual Incentive Plan (the 2009 Plan), which was approved by shareholders on November 19, 2009. Under the 2009 Plan, the Company s Board of Directors may grant stock options, restricted stock awards and other stock-based awards to officers or other employees of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board. Grants of service-based awards are valued at our common stock price at the date of grant. The Company did not grant any stock-based awards during the nine months ended March 31, 2012 or 2011.

In November 2010, the Company s Board of Directors (the Board) approved the immediate vesting of all outstanding stock options under both the 1999 Stock Incentive Plan and the 2009 Plan. Additionally, the Board authorized management to net-settle any outstanding stock options in cash. The option holder had a choice of receiving cash upon net settlement of options or to settle options for shares of the Company. Such modification of the stock options resulted in recognizing a liability equal to the portion of each award attributable to past service multiplied by the modified award s fair value, and was adjusted quarterly. The accelerated vesting and modification affected no other terms or conditions of the options, including the number of outstanding options or exercise price. As of March 31, 2012, the Company did not record such a liability as a result of the final options being net-settled for cash of approximately $465,000.

During the nine months ended March 31, 2012 and 2011, the Company recorded stock-based compensation charges of approximately $3,000 and $1.4 million, respectively, to general and administrative expense for restricted stock and option awards.

Recent Accounting Pronouncements. In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-11 *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual and interim periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the disclosures in our financial statements.

3. Natural Gas and Oil Exploration and Production Risk

The Company s future financial condition and results of operations will depend upon prices received for its natural gas and oil production and the cost of finding, acquiring, developing and producing reserves. Substantially all of its production is sold under various terms and arrangements at prevailing market prices. Prices for natural gas and oil are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company s control.

Other factors that have a direct bearing on the Company s financial condition are uncertainties inherent in estimating natural gas and oil reserves and future hydrocarbon production and cash flows, particularly with respect to wells that have not been fully tested and with wells having limited production histories; the timing and costs of our future drilling; development and abandonment activities; access to additional capital; changes in the price of natural gas and oil; availability and cost of services and equipment; and the presence of competitors with greater financial resources and capacity. The preparation of our consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect our reported results of operations, the amount of reported assets, liabilities and contingencies, and proved natural gas and oil reserves.

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4. Customer Concentration Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. Major purchasers of our natural gas and oil for the nine months ended March 31, 2012 were ConocoPhillips Company, Shell Trading US Company, Exxon Mobil Oil Corporation, Trans Louisiana Gas Pipeline, Inc., NJR Energy Services and Enterprise Products Operating LLC. Our sales to these companies are not secured with letters of credit and in the event of non-payment, we could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on our financial position, but there currently are numerous other potential purchasers of our production.

5. Net Income per Common Share

A reconciliation of the components of basic and diluted net income per share of common stock is presented in the tables below:

	Three Months Ended March 31, 2012			Three Months Ended March 31, 2011		
	Income	Shares	Per Share	Income	Shares	Per Share
	(thousands, except per share amounts)					
Income from continuing operations	$ 14,700	15,357	$ 0.96	$ 16,641	15,665	$ 1.06
Discontinued operations, net of income taxes	(26)	15,357	(0.00)	156	15,665	0.01
Basic Earnings per Share:						
Net income attributable to common stock	$ 14,674	15,357	$ 0.96	$ 16,797	15,665	$ 1.07
Effect of Potential Dilutive Securities:						
Stock options, net of shares assumed purchased		3			2	
Income from continuing operations	14,700	15,360	0.96	16,641	15,667	1.06
Discontinued operations, net of income taxes	(26)	15,360	(0.00)	156	15,667	0.01
Diluted Earnings per Share:						
Net income attributable to common stock	$ 14,674	15,360	$ 0.96	$ 16,797	15,667	$ 1.07

	Nine Months Ended March 31, 2012			Nine Months Ended March 31, 2011		
	Income	Shares	Per Share	Income	Shares	Per Share
	(thousands, except per share amounts)					
Income from continuing operations	$ 49,875	15,453	$ 3.23	$ 46,366	15,665	$ 2.96
Discontinued operations, net of income taxes	(821)	15,453	(0.05)	1,139	15,665	0.07
Basic Earnings per Share:						
Net income attributable to common stock	$ 49,054	15,453	$ 3.18	$ 47,505	15,665	$ 3.03
Effect of Potential Dilutive Securities:						
Stock options, net of shares assumed purchased		3			64	
Income from continuing operations	49,875	15,456	3.23	46,366	15,729	2.95
Discontinued operations, net of income taxes	(821)	15,456	(0.05)	1,139	15,729	0.07
Diluted Earnings per Share:						
Net income attributable to common stock	$ 49,054	15,456	$ 3.18	$ 47,505	15,729	$ 3.02

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6. Credit Facility

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the Credit Agreement). The Credit Agreement currently has a $40 million hydrocarbon borrowing base and is available to fund the Company s exploration and development activities, as well as repurchase shares of common stock, pay dividends and fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and effective November 1, 2011, a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of March 31, 2012, the Company was in compliance with all covenants and had no borrowings outstanding under the Credit Agreement.

7. Discontinued Operations

Joint Venture Assets

In October 2009, the Company entered into a joint venture with Patara Oil & Gas LLC (Patara) to develop proved undeveloped Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company s board of directors, is the Chief Executive Officer of Patara. On May 13, 2011 the Company sold substantially all of its onshore Texas assets to Patara for $40 million ($38.7 million after adjustments). The properties were sold effective April 1, 2011 and included: (i) the Company s 90% interest and 5% overriding royalty interest in the 21 wells drilled under the joint venture with Patara (the Joint Venture Assets); (ii) the Company s 100% working interest (72.5% net revenue interest) in Rexer #1 drilled in south Texas; and (iii) a 75% working interest (54.4% net revenue interest) in Rexer-Tusa #2. The Company has accounted for the sale of the Joint Venture Assets as discontinued operations as of June 30, 2011 and reclassified the results of its operations to discontinued operations for the three and nine months ended March 31, 2011.

The Joint Venture Assets had proved reserves of approximately 16.7 Bcfe, net to Contango. The summarized financial results for the Joint Venture Assets for each of the periods presented were as follows:

	Three Months Ended March 31,		Nine Months Ended March 31,	
	2012	2011	2012	2011
	(thousands)		(thousands)	
Results of Operations:				
Revenues	$	$ 2,683	$	$ 6,799
Operating expenses	(40)	(635)	(40)	(1,421)
Depletion expenses		(1,332)		(3,681)
Exploration expenses				(529)
Gain (Loss) before income taxes	(40)	716	(40)	1,168
Provision for income taxes	14	(251)	14	(409)
Gain (Loss) from discontinued operations, net of income taxes	$ (26)	$ 465	$ (26)	$ 759

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Rexer Assets

In October 2011, the Company sold its remaining 25% working interest (18.4% net revenue interest) in Rexer-Tusa #2 for $10,000 to Patara (together with the 75% working interest sold in Rexer-Tusa #2 and the 100% working interest sold in Rexer #1, the Rexer Assets). The sale was effective October 1, 2011.The Company has accounted for the sale of the Rexer Assets as discontinued operations as of March 31, 2012 and reclassified the results of operations for the Rexer Assets to discontinued operations for all periods presented. The summarized financial results for the Rexer Assets for each of the periods presented were as follows:

	Three Months Ended March 31, 2012 (thousands)	Three Months Ended March 31, 2011 (thousands)	Nine Months Ended March 31, 2012 (thousands)	Nine Months Ended March 31, 2011 (thousands)
Results of Operations:				
Revenues	$	$ 836	$ 6	$ 1,724
Operating expenses		(100)	(22)	(251)
Depletion expenses		(1,212)		(2,593)
Exploration expenses			(7)	
Impairment of natural gas and oil properties			(1,031)	
Loss on sale of discontinued operations			(169)	
Gain (Loss) before income taxes		(476)	(1,223)	(1,120)
Provision for income taxes		167	428	392
Gain (Loss) from discontinued operations, net of income taxes	$	$ (309)	$ (795)	$ (728)

Contango Mining Company

On September 29, 2010, Contango ORE, Inc. (CORE), then a wholly-owned subsidiary of the Company formed to explore for gold and rare earth elements in Alaska, filed with the Securities and Exchange Commission a Registration Statement on Form 10 which became effective November 29, 2010. Following the effective date, CORE acquired the assets and assumed the liabilities of Contango Mining Company (Contango Mining), another wholly-owned subsidiary of the Company. Additionally, subsequent to the effective date, the Company contributed $3.5 million of cash to CORE. In exchange, CORE issued approximately 1.6 million shares of its common stock to the Company. The Company distributed all its shares of CORE, valued at approximately $7.3 million, to its stockholders of record as of October 15, 2010 on the basis of one share of common stock of CORE for each ten shares of the Company s common stock then outstanding. In addition to the distribution of shares of CORE, the Company paid $6,213 in cash to its stockholders of record in exchange for partial shares.

As of March 31, 2012 and June 30, 2011, the assets and liabilities of Contango Mining were excluded from the Company s financial statements.

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Results of operations of Contango Mining for the nine months ended March 31, 2011 are included in discontinued operations in the Company s Statement of Operations. No income or expenses related to CORE were recognized for the nine months ended March 31, 2012, or for the three months ended March 31, 2011. The summarized financial results for CORE included in discontinued operations were as follows:

	Nine Months Ended March 31, 2011 (thousands)
Results of Operations:	
Revenues	$
Expenses	(1,136)
Gain on sale of discontinued operations	2,737
Gain before income taxes	1,601
Provision for income taxes	(493)
Gain from discontinued operations, net of income taxes	$ 1,108

8. Income Taxes

The Company s income tax provision for continuing operations consists of the following:

	Three Months Ended March 31,		Nine Months Ended March 31,	
	2012	2011	2012	2011
	(thousands)		(thousands)	
Current income tax expense	$ 11,540	$ 9,771	$ 31,479	$ 32,265
Deferred income tax benefit	(3,598)	(653)	(2,731)	(5,824)
Total income tax expense	$ 7,942	$ 9,118	$ 28,748	$ 26,441

9. Related Party Transactions

In February 2012, the Company net-settled 45,000 stock options from two employees for a total of approximately $465,000. During the nine months ended March 31, 2011, the Company purchased 172,544 shares of its common stock for a total of approximately $9.8 million. Of this amount, 149,573 shares were purchased from four employees and one member of its board of directors for a total of approximately $8.7 million. All the purchases were approved by the Company s board of directors and were completed at the closing price of the Company s common stock on the date of purchase.

In November 2011, the Company executed a $1.0 million Revolving Line of Credit Promissory Note to lend money to CORE (the CORE Note). The Company and CORE share executive officers. The CORE Note contains covenants limiting CORE s ability to enter into additional indebtedness and prohibiting liens on any of its assets or properties. Borrowings under the CORE Note bear interest at 10% per annum. Principal and interest are due from CORE to the Company on December 31, 2012, and may be prepaid at any time with no prepayment penalty.

On March 30, 2012 the Company received the $500,000 it had advanced under the CORE Note, plus accrued interest of approximately $15,000. CORE may re-borrow any portion of the $1.0 million through December 31, 2012.

In March 2006, the Company executed a Promissory Note (the COE Note) to lend money to Contango Offshore Exploration LLC (COE) to finance its share of development costs in Grand Isle 72. As of May 31, 2010, COE owed the Company $4.3 million under the COE Note, and an additional $1.6 million in accrued and

unpaid interest. Effective June 1, 2010, COE was dissolved and the Company, as a member of COE, assumed its 65.6% of the obligation of COE, while the other member of COE assumed the remaining 34.4%, or approximately $2.0 million. The note receivable was paid in full on October 27, 2010.

10. Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company s board of directors approved a $100 million share repurchase program. All shares are purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes.

During the nine months ended March 31, 2012, the Company purchased 271,837 shares at an average price of $55.38 per share, for a total of approximately $15.1 million. The $100 million share repurchase program concluded in October 2011 with the Company having purchased 2,157,278 shares of its common stock at an average cost per share of $46.35 per share, for a total of approximately $100 million under the $100 million share repurchase program.

$50 Million Share Repurchase Program

On September 28, 2011, the Company s Board of Directors approved the adoption of a $50 million share repurchase program, effective upon completion of purchases under the Company s $100 million share repurchase program. The purchases made under the $50 million share repurchase program will be subject to the same terms and conditions as purchases made under the $100 million share repurchase program. During the nine months ended March 31, 2012, the Company purchased 35,663 shares at an average price of $54.58 per share, for a total of approximately $1.9 million under the $50 million share repurchase program. Additionally, in February 2012 the Company net-settled 45,000 options from two employees for a total of approximately $465,000.

In total, under both share repurchase programs combined, the Company has purchased approximately 2.2 million shares of its common stock at an average cost per share of $46.49, and 45,000 stock options, for a total of approximately $102.4 million as of March 31, 2012, bringing its total share count to 15,357,166 shares of common stock outstanding.

11. Subsequent Events

On April 9, 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the LLC Agreement) to form Exaro Energy III LLC (Exaro) effective as of March 31, 2012. Pursuant to the LLC Agreement, the Company has committed to invest up to $82.5 million in Exaro over the next five years together with other parties for an aggregate commitment of $182.5 million. The Company owns approximately a 45% interest in Exaro, subject to terms allowing another party to acquire up to $15 million of the Company s commitment, which would decrease the Company s interest in Exaro to approximately 37%. In April 2012, the Company invested approximately $41.3 million in Exaro.

On April 10, 2012, the Company announced that Mr. Brad Juneau had joined the Company s board of directors and that the Company had entered into an Advisory Agreement with Juneau Exploration, L.P. (JEX), whereby JEX will advise Contango s staff on operational matters including drilling, completions, production and accounting. JEX and its seven employees, including Mr. Juneau, will also continue to generate offshore and onshore prospects for the Company. Pursuant to the Advisory Agreement, JEX will be paid a monthly fee of approximately $167,000 and JEX, or employees of JEX, will continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights.

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Available Information

General information about us can be found on our website at www.contango.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission (SEC).

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and the accompanying notes and other information included elsewhere in this Form 10-Q and in our Form 10-K for the fiscal year ended June 30, 2011, previously filed with the SEC.

Cautionary Statement about Forward-Looking Statements

Some of the statements made in this report may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases should be , will be , believe , expect , anticipate , estimate , forecast , goal and similar expressions identify forward-looking statements and express our expectations about future events. These include such matters as:

Our financial position

Business strategy, including outsourcing

Meeting our forecasts and budgets

Anticipated capital expenditures

Drilling of wells

Natural gas and oil production and reserves

Timing and amount of future discoveries (if any) and production of natural gas and oil

Operating costs and other expenses

Cash flow and anticipated liquidity

Prospect development

Property acquisitions and sales

- New governmental laws and regulations

- Expectations regarding oil and gas markets in the United States

Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from future results expressed or implied by the forward-looking statements. These factors include among others:

- Low and/or declining prices for natural gas and oil

- Natural gas and oil price volatility

- Operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and gas processing facilities

- The risks associated with acting as the operator in drilling deep high pressure and temperature wells in the Gulf of Mexico, including well blowouts and explosions

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The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which the Company has made a large capital commitment relative to the size of the Company s capitalization structure

The timing and successful drilling and completion of natural gas and oil wells

Availability of capital and the ability to repay indebtedness when due

Availability of rigs and other operating equipment

Ability to receive Bureau of Ocean Energy Management, Regulation and Enforcement permits on a time schedule that permits the Company to operate efficiently

Ability to raise capital to fund capital expenditures

Timely and full receipt of sale proceeds from the sale of our production

The ability to find, acquire, market, develop and produce new natural gas and oil properties

Interest rate volatility

Zero or near zero interest rates

Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures

Operating hazards attendant to the natural gas and oil business

Downhole drilling and completion risks that are generally not recoverable from third parties or insurance

Potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps

Weather

Availability and cost of material and equipment

Delays in anticipated start-up dates

Actions or inactions of third-party operators of our properties

Actions or inactions of third-party operators of pipelines or processing facilities

The ability to find and retain skilled personnel

Strength and financial resources of competitors

Federal and state regulatory developments and approvals

Environmental risks

Worldwide economic conditions

The ability to construct and operate offshore infrastructure, including pipeline and production facilities

The continued compliance by the Company with various pipeline and gas processing plant specifications for the gas and condensate produced by the Company

Drilling and operating costs, production rates and ultimate reserve recoveries in our Eugene Island 10 (Dutch) and State of Louisiana (Mary Rose) acreage

Restrictions on permitting activities

Expanded rigorous monitoring and testing requirements

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Legislation that may regulate drilling activities and increase or remove liability caps for claims of damages from oil spills

Ability to obtain insurance coverage on commercially reasonable terms

Accidental spills, blowouts and pipeline ruptures

Impact of new and potential legislative and regulatory changes on Gulf of Mexico operating and safety standards

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events. See the information under the heading Risk Factors in this Form 10-Q for some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in forward-looking statements.

Overview

Contango Oil & Gas Company (Contango or the Company) is a Houston-based, independent natural gas and oil company. The Company s core business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet. Contango Operators, Inc. (COI), our wholly-owned subsidiary, acts as operator on our prospects.

Our Strategy

Our exploration strategy is predicated upon two core beliefs: (1) that the only competitive advantage in the commodity-based natural gas and oil business is to be among the lowest cost producers and (2) that virtually all the exploration and production industry s value creation occurs through the drilling of successful exploratory wells. As a result, our business strategy includes the following elements:

Funding exploration prospects generated by Juneau Exploration, L.P., our alliance partner. We depend primarily upon our alliance partner, Juneau Exploration, L.P. (JEX), for prospect generation expertise. JEX is experienced and has a successful track record in exploration.

Using our limited capital availability to increase our reward/risk potential on selective prospects. We have concentrated our risk investment capital in exploration of i) offshore Gulf of Mexico prospects and ii) conventional and unconventional onshore plays. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. COI drills and operates our prospects. Should we be successful in any of our offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status.

Sale of proved properties. From time-to-time as part of our business strategy, we have sold and in the future expect to continue to sell some or a substantial portion of our proved reserves and assets to capture current value, using the sales proceeds to further our exploration activities. Since its inception, the Company has sold approximately $524 million worth of natural gas and oil properties, and views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, and as a source of funds for potentially higher rate of return natural gas and oil exploration opportunities.

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Controlling general and administrative and geological and geophysical costs. Our goal is to be among the most efficient in the industry in revenue and profit per employee and among the lowest in general and administrative costs. We plan to continue outsourcing our geological, geophysical, and reservoir engineering and land functions, and partnering with cost efficient operators. We have eight employees.

Structuring incentives to drive behavior. We believe that equity ownership aligns the interests of our employees and stockholders. Our directors and executive officers beneficially own or have voting control over approximately 17% of our common stock.

Impact of Deepwater Horizon Incident

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill, and highlighted the dangers associated with exploration and production activities.

The legislative and regulatory response to the Deepwater Horizon Incident is ongoing. In 2010, the US Department of the Interior issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to regulate drilling activities and increase liability. In January 2011, the President s National Commission on the Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps.

Additional regulatory review, slower permitting processes and increased oversight have resulted in longer development cycle time for our Gulf of Mexico projects. Cycle time is the length of time it takes for a project to progress from developing a prospect to beginning production, and longer development cycle times could result in lower rates of return on our investments.

Increased regulation impacting our activities in the Gulf of Mexico could result in extensive efforts to ensure compliance and incremental compliance costs. A significant delay or cancellation of our planned Gulf of Mexico exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production over time. To the extent current exploration activities are significantly delayed, a gap could occur in our long-term production profile with a negative impact on our operating results and cash flows.

Additional legislation or regulation is being discussed which could require each company doing business in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility (COFR), a certificate required by the Oil Pollution Act of 1990 which evidences a company s financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

Future legislation or regulation is also likely to result in substantial increases in civil or criminal fines or sanctions. Such fines or sanctions could well exceed the actual cost of containment and cleanup associated with a well incident or spill. We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the Deepwater Horizon Incident is not yet known.

Risk and Insurance Program Update

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties attributed to certain assets and including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We expect the future availability and cost of insurance to be impacted by the Deepwater Horizon Incident. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor the expected regulatory and legislative response and its impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows.

We carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. As a result of the Deepwater Horizon Incident, we have increased our well control coverage from $75 million to $100 million on certain wells, which covers control of wells, pollution cleanup and consequential damages. We have increased our general liability coverage from $100 million to $150 million, which covers pollution cleanup, consequential damages coverage, and third party personal injury and death. We have also increased our Oil Spill Financial Responsibility coverage from $35 million to $150 million, which covers additional pollution cleanup and third party claims coverage.

Health, Safety and Environmental Program

The Company s Health, Safety and Environmental (HS&E) Program is supervised by an operating committee of senior management to insure compliance with all state and federal regulations. In addition, to support the operating committee, we have a contract in place with J. Connors Consulting (JCC) to manage our regulatory process. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico regulatory process, preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills to oil and gas companies and pipeline operators.

For our Gulf of Mexico operations, we have a Regional Oil Spill Plan in place. Our response team is trained annually and is tested through annual spill drills. In addition, we have in place a contract with O Brien s Response Management (O Brien s). O Brien s maintains a 24/7 manned incident command center located in Slidell, LA. Upon the occurrence of an oil spill, the Company s spill program is initiated by notifying O Brien s that we have an emergency. While the Company would focus on source control of the spill, O Brien s would handle all communication with state and federal agencies as well as U.S. Coast Guard notifications.

If a spill were to occur, we would use Clean Gulf Associates (CGA) to assist with equipment and personnel needs. CGA specializes in onsite control and cleanup and is on 24 hour alert with equipment currently stored at six bases (Ingleside, Galveston, Lake Charles, Houma, Venice and Pascagoula), and is opening new sites in Leeville, Morgan City and Harvey, Louisiana. The CGA equipment stockpile includes skimming vessels which can operate in open seas or shallow waters; protective booming to use in open seas or near shorelines; communication equipment; dispersants; and boat spray systems to apply dispersants. CGA also has retainers with an aerial dispersant company and a company that provides mechanical recovery equipment for spill responses. Additionally, CGA provides wildlife rehabilitation services and a forward command center. Some of the CGA equipment includes:

HOSS Barge: the largest purpose-built skimming barge in the United States with 4,000 barrels of storage capacity.

Fast Response System (FRU): a self-contained skimming system for use on vessels of opportunity. CGA has nine of these units.

Fast Response Vessels (FRV): four 46 foot FRVs with cruise speeds of 20-25 knots that have built-in skimming troughs and cargo tanks, outrigger skimming arms, navigation and communication equipment.

In addition to being a member of CGA, we have a contract in place with Wild Well Control for source control at the wellhead if required. Wild Well Control is one of the world s leading providers of firefighting, well control, engineering, and training services.

Safety and Environmental Management System (SEMS)

The Company has developed and implemented a Safety and Environmental Management System (SEMS) to address oil and gas operations in the Outer Continental Shelf (OCS), as required by the Bureau of Safety and Environmental Enforcement (BSEE). Full implementation of the following thirteen mandatory elements of the American Petroleum Institute s Recommended Practice 75 (API RP 75) was required on or before November 15, 2011:

General Provisions

Safety and Environmental Information

Hazards Analyses

Management of Change

Operating Procedures

Safe Work Practices

Training

Mechanical Integrity

Pre-Startup Review

Emergency Response and Control

Investigation of Accidents

Audits

Records and Documentation

Our SEMS program identifies, addresses, and manages safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company must establish goals, performance measures, training, accountability for its implementation, and provide necessary resources for an effective SEMS, as well as review the adequacy and effectiveness of the SEMS program. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. We have contracted with Island Technologies Inc. to manage our SEMS program for production operations.

The BSEE will enforce the SEMS requirements via audits. We must have our SEMS program audited by either an independent third-party or our designated and qualified personnel within 2 years of the initial implementation and at least once every 3 years thereafter. Failure of an audit may force us to shut-in our Gulf of Mexico operations.

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Exploration Alliance with JEX

JEX is a private company formed for the purpose of assembling domestic natural gas and oil prospects, either individually, or via our 32.3% owned affiliated company, Republic Exploration LLC (REX) (see Offshore Gulf of Mexico Exploration Joint Ventures below). In addition to generating new prospects, JEX occasionally evaluates exploration prospects generated by third-party independent companies for us to purchase. Once we have purchased a prospect from JEX, REX or a third-party, we have historically entered into a participation agreement and joint operating agreement specifying each participant s working interest, net revenue interest, and description of when such interests are earned, as well as allocating an overriding royalty interest of up to 3.33% to benefit employees of JEX.

On April 10, 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of JEX, had joined the Company s board of directors and that the Company had entered into an Advisory Agreement with JEX, whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will advise Contango s staff on operational matters including drilling, completions, production and accounting. Pursuant to the Advisory Agreement, JEX will be paid a monthly fee of approximately $167,000 and JEX, or employees of JEX, will continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights.

Offshore Gulf of Mexico Exploration Joint Ventures

Contango, through its wholly-owned subsidiary COI, and its partially-owned subsidiary REX, conducts exploration activities in the Gulf of Mexico. As of April 30, 2012, Contango, through COI and REX, had an interest in 16 offshore leases. See Offshore Properties for additional information on our offshore properties.

Contango Operators, Inc.

COI, a wholly-owned subsidiary of the Company, drills and operates our wells in the Gulf of Mexico, as well as submits bids in lease sales and acquires leasehold acreage. Additionally, COI may acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, under farm-out agreements, or similar agreements, with REX, JEX and/or third parties.

As of April 30, 2012, the Company s offshore production was approximately 94.5 million cubic feet equivalent per day (Mmcfed), net to Contango, which consists mainly of seven federal and five State of Louisiana wells in the shallow waters of the Gulf of Mexico. These 12 operated wells produce through the following four platforms:

Eugene Island 11 Platform

Our Company-owned and operated platform at Eugene Island 11 was designed with a capacity of 500 million cubic feet per day (Mmcfd) and 6,000 barrels of oil per day (bopd). In September 2010 the Company completed installing a companion platform and two pipelines adjacent to the Eugene Island 11 platform to be able to access alternate markets. These platforms service production from the Company s five Mary Rose wells which are all located in State of Louisiana waters, as well as our Dutch #4 and Dutch #5 wells which are both located in federal waters. From these platforms, we flow the majority of our gas to an American Midstream pipeline via our 8 pipeline, which has been designed with a capacity of 80 Mmcfd, and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. We flow our condensate via an ExxonMobil pipeline to on-shore markets and multiple refineries.

Alternatively, our gas and condensate can flow to our Eugene Island 63 auxiliary platform via our 20 pipeline, which has been designed with a capacity of 330 Mmcfd and 6,000 bopd, and then from there to third-party owned and operated on-shore processing facilities near Patterson, Louisiana, via an ANR pipeline.

Eugene Island 24 Platform

This third-party owned and operated production platform at Eugene Island 24 was designed with a capacity of 100 Mmcfd and 3,000 bopd. This platform services production from the Company s Dutch #1, #2 and #3 federal wells. From this platform, the gas flows through an American Midstream pipeline into a third-party owned and operated on-shore processing facility at Burns Point, Louisiana, and the condensate flows via an ExxonMobil pipeline to on-shore markets and multiple refineries.

Ship Shoal 263 Platform

Our Company-owned and operated platform at Ship Shoal 263 was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services natural gas and condensate production from our Nautilus well, which both flow via the Transcontinental Gas Pipeline to onshore processing plants.

Vermilion 170 Platform

Our Company-owned and operated platform at Vermilion 170 was designed with a capacity of 60 Mmcfd and 2,000 bopd. This platform services natural gas and condensate production from our Swimmy well which began producing in September 2011. The production flows via the Sea Robin Pipeline to onshore processing plants.

Other Activities

On March 1, 2012, the Company was awarded Brazos Area 543 by the Bureau of Ocean Energy Management (BOEM), which was bid on at the Western Gulf of Mexico Lease Sale No. 218 held on December 14, 2011. As of April 30, 2012, the Company had paid approximately $250,000 in leasehold costs on Brazos Area 543.

On December 21, 2011, the Company purchased an additional 3.66% working interest (2.67% net revenue interest) in Mary Rose #5 (previously Eloise North) for approximately $203,000, from an existing partner. As of March 31, 2012, the Company s working interest and net revenue interest in Mary Rose #5 was 37.80% and 27.59%, respectively.

In October 2011, we commenced a workover of our Eloise North well to recomplete the well in the upper Rob-L sands. During the workover, the Company experienced difficulties and unexpected delays due to malfunctioning production tree valves, coiled tubing equipment failures, weather delays, and stuck equipment in the tubing. As a result, the Company plugged the Rob-L sands in January 2012 and recompleted uphole in the Cib-Op sands as our Mary Rose #5 well, at a cost of approximately $0.5 million, net to Contango, based on the new higher ownership percentage and inclusive of a required well cost adjustment. The Mary Rose #5 well began producing on January 26, 2012 and is currently flowing intermittently.

Effective February 24, 2011, the Company purchased the deep mineral rights on Ship Shoal 134 (Eagle) from an independent third-party oil and gas company. The exploration plan and application for permit to drill have both been approved by the BOEM. We expect to spud this well by the end of the fiscal year, once a rig becomes available. We have a 100% working interest in this wildcat exploration prospect, subject to back-ins if successful, and have budgeted approximately $25.0 million to drill this well. We have also invested $6.0 million in acquiring leases associated with Eagle.

In August 2011, we farmed in South Timbalier 75 (Fang) from an independent third party oil and gas company. Our exploration plan and application for permit to drill have both been approved by the BOEM. We expect to spud this well once a rig becomes available. Under the terms of the farmout agreement, we have until September 2012, subject to rig availability and/or regulatory permit approval delays, to drill this well. Contango has a 100% working interest, subject to back-ins if successful, and has budgeted to invest approximately $25.0 million to drill this well.

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Republic Exploration LLC

West Delta 36, a REX prospect, is operated by a third party. The Company depends on a third-party operator for the operation and maintenance of this production platform. As of April 30, 2012, the well was producing at a rate of approximately 0.1 Mmcfed, net to Contango. REX has a 25.0% working interest (WI), and a 20.0% net revenue interest (NRI), in this well.

Offshore Properties

Producing Properties. The following table sets forth the interests owned by Contango through its affiliated entities in the Gulf of Mexico which were capable of producing natural gas or oil as of April 30, 2012:

Area/Block	WI	NRI	Status
Eugene Island 10 #D-1 (Dutch #1)	47.05%	38.1%	Producing
Eugene Island 10 #E-1 (Dutch #2)	47.05%	38.1%	Producing
Eugene Island 10 #F-1 (Dutch #3)	47.05%	38.1%	Producing
Eugene Island 10 #G-1 (Dutch #4)	47.05%	38.1%	Producing
Eugene Island 10 #I-1 (Dutch #5)	47.05%	38.1%	Producing
S-L 18640 #1 (Mary Rose #1)	53.21%	40.5%	Producing
S-L 19266 #1 (Mary Rose #2)	53.21%	38.7%	Producing
S-L 19266 #2 (Mary Rose #3)	53.21%	38.7%	Producing
S-L 18860 #1 (Mary Rose #4)	34.58%	25.5%	Producing
S-L 19266 #3 & S-L 19261 (Mary Rose #5)	37.80%	27.6%	Producing
Ship Shoal 263 (Nautilus)	100.00%	80.0%	Producing
Vermilion 170 (Swimmy)	87.24%	68.0%	Producing
West Delta 36 (produced via REX)	8.1%	6.5%	Producing

Leases. The following table sets forth the working interests owned by Contango and affiliated entities in non-developed leases in the Gulf of Mexico as of April 30, 2012.

Area/Block	WI	Lease Date	Expiration Date
<u>*Contango Operators, Inc.:*</u>			
S-L 19396	53.21%	Jun-07	Jun-12
Eugene Island 11	53.21%	Dec-07	Dec-12
East Breaks 369 (1)	(2)	Dec-03	Dec-13
South Timbalier 97 (via REX)	32.30%	Jun-09	Jun-14
Ship Shoal 121	100.00%	Jul-10	Jul-15
Ship Shoal 122	100.00%	Jul-10	Jul-15
Brazos Area 543	100.00%	Mar-12	Mar-17
Ship Shoal 134	100.00%	(3)	(3)
South Timbalier 75	100.00%	(4)	(4)

(1) Dry Hole
(2) Farm-out. COI retains a 2.41% ORRI
(3) Purchased deep rights. Lease is held by production from shallow wells owned by third-party
(4) Farm-in.

Onshore Exploration and Properties

Alta Investments

On April 12, 2011, the Company announced a commitment to invest up to $20 million over two years in Alta Energy Canada Partnership, G.P. (Alta Energy), a venture that will acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets. As of March 31, 2012, we

had invested approximately $11.4 million in Alta Energy to purchase over 60,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. Alta Energy s plans are to continue to invest in the area and drill up to four wells in 2012. Contango owns a 5% interest in most of the acreage acquired by Alta Energy.

Exaro Energy III LLC

On April 9, 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the LLC Agreement) to form Exaro Energy III LLC (Exaro). Pursuant to the LLC Agreement, the Company has committed to invest up to $82.5 million in Exaro over the next five years together with other parties for an aggregate commitment of $182.5 million. The Company owns approximately a 45% interest in Exaro, subject to terms allowing another party to acquire up to $15 million of the Company s commitment, which would decrease the Company s interest in Exaro to approximately 37%. As of April 2012, the Company has invested approximately $41.3 million in Exaro.

Exaro has entered into an Earning and Development Agreement (the EDA Agreement) with Encana Oil & Gas (USA) Inc. (Encana) to provide funding of up to $380 million to continue the development drilling program in a defined area of Encana s Jonah field asset located in Sublette County, Wyoming. This funding will be comprised of the $182.5 million investment detailed above, debt, and cash flow from operations. Encana will continue to be the operator of the field and upon investing the full amount of the $380 million, Exaro will have earned 32.5% of Encana s working interest in a defined joint venture area that comprises approximately 5,760 gross acres.

On-shore Shale Play

As of April 30, 2012, the Company has invested approximately $5 million to lease approximately 14,000 acres in an unconventional shale play in the southeastern portion of the United States. The Company has no expected spud date yet but will wait to see what type of information can be learned from wells drilled in the area.

Employees

We have eight employees, all of whom are full time employees. The Company outsources its human resources function to Insperity, Inc. (formerly Administaff Companies II, LP) and all of the Company s employees are co-employees of Insperity, Inc.

Application of Critical Accounting Policies and Management s Estimates

The discussion and analysis of the Company s financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company s significant accounting policies are described in Note 2 to the consolidated financial statements included in this Quarterly Report on Form 10-Q. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to its natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company s consolidated financial statements:

Successful Efforts Method of Accounting. Our application of the successful efforts method of accounting for our natural gas and oil business activities requires judgments as to whether particular wells are developmental or

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exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management s judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Reserve Estimates. While we are reasonably certain of recovering our reported reserves, the Company s estimates of natural gas and oil reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable natural gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing natural gas and oil prices, operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected natural gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company s natural gas and oil properties and/or the rate of depletion of such natural gas and oil properties. Actual production, revenues and expenditures with respect to the Company s reserves will likely vary from estimates, and such variances may be material. Holding all other factors constant, a reduction in the Company s proved reserve estimate at March 31, 2012 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $1.9 million, $4.0 million and $6.3 million, respectively.

Impairment of Natural Gas and Oil Properties. The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company compares expected undiscounted future net cash flows from each field to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company s estimate of future natural gas and oil prices, operating costs, and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Given the complexities associated with natural gas and oil reserve estimates and the history of price volatility in the natural gas and oil markets, events may arise that will require the Company to record an impairment of its natural gas and oil properties and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

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Income Taxes. Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

MD&A Summary Data

The following table shows the relationship between our produced volumes and the revenues they derive.

	Three Months Ended March 31,			
	2012		2011	
	(thousands, except percentage)			
Natural gas volumes (Mcf)	5,547	73.62%	5,821	74.67%
Condensate and NGL volumes (Mcfe)	1,988	26.38%	1,975	25.33%
Total volumes	7,535		7,796	
Natural gas revenues	$ 14,246	34.46%	$ 26,168	50.51%
Condensate and NGL revenues	27,093	65.54%	25,637	49.49%
Total revenues	$ 41,339		$ 51,805	

	Nine Months Ended March 31,			
	2012		2011	
	(thousands, except percentage)			
Natural gas volumes (Mcf)	17,276	75.04%	19,022	75.33%
Condensate and NGL volumes (Mcfe)	5,745	24.96%	6,229	24.67%
Total volumes	23,021		25,251	
Natural gas revenues	$ 58,669	42.07%	$ 82,795	54.07%
Condensate and NGL revenues	80,780	57.93%	70,343	45.93%
Total revenues	$ 139,449		$ 153,138	

The table below sets forth average daily production data in Mmcfed from our offshore wells for each of the periods presented:

	Three Months Ended			
Production	**June 30, 2011**	**September 30, 2011**	**December 31, 2011**	**March 31, 2012**
Dutch and Mary Rose Wells	66.0	59.5	64.3	55.2
Mary Rose #5 (Eloise North) and Dutch #5 (Eloise South)	0.1	3.7	1.9	4.1
Ship Shoal 263 Well (Nautilus)	9.7	7.6	10.9	7.8
Vermilion 170 Well (Swimmy)		2.3	17.2	15.3
Non-operated wells	0.1	0.3	0.2	0.3
	75.9	73.4	94.5	82.7

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Dutch and Mary Rose Wells

Third-party platform and pipeline repairs, as well as third-party gas processing plant shut-ins reduced our flowrates at our Dutch #1, #2, and #3 wells during the three months ended September 2011. During the three months ended March 31, 2012 our Dutch #1, #2 and #3 wells were shut in for a total of 10 days for maintenance and to repair a small pipeline leak. As of April 30, 2012, these eight wells were flowing approximately 63.3 Mmcfed, net to Contango.

Mary Rose #5 (Eloise North) and Dutch #5 (Eloise South)

The near-zero production related to our Eloise North and South wells for the three months ended June 30, 2011 is due to the depletion of the lower Rob-L sands in these two wells. Our Eloise North well began producing from the lower Rob-L sands in December 2008, sanded up in February 2011 and ceased production. The Company completed a workover in late June 2011 and resumed production, but the well ceased production again by mid-September 2011. The well was recompleted uphole in the Cib-Op section as our Mary Rose #5 well in January 2012. In March 2012, production once again ceased and the well was shut-in. The well is currently flowing intermittently.

Our Eloise South well began producing from the Rob-L sands in July 2010 and in October 2010 the well ceased production. In July 2011, we recompleted the Eloise South well uphole in the Cib-Op section as our Dutch #5 well. As of April 30, 2012, this well was flowing at approximately 2.2 Mmcfed, net to Contango.

Ship Shoal 263 Well (Nautilus)

For the three months ended September 30, 2011, production at Ship Shoal 263 was temporarily shut-in due to a leak on a third-party owned and operated pipeline. For the three months ended March 31, 2012, production was intermittent due to overheating and scaling problems. As of April 30, 2012, the well was flowing at approximately 14.0 Mmcfed, net to Contango.

Vermilion 170 Well (Swimmy)

Our Vermilion 170 well began production in September 2011, and as of April 30, 2012, was flowing at approximately 14.9 Mmcfed, net to Contango.

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The table below sets forth revenue, expense and production data for the three and nine months ended March 31, 2012 and 2011.

	Three Months Ended March 31,			Nine Months Ended March 31,		
	2012	2011	Change	2012	2011	Change
	(thousands, except percent change, average sales price and selected data per Mcfe)			(thousands, except percent change, average sales price and selected data per Mcfe)		
Revenues:						
Natural gas and oil sales	$ 41,339	$ 51,805	-20%	$ 139,449	$ 153,138	-9%
Total revenues	$ 41,339	$ 51,805	-20%	$ 139,449	$ 153,138	-9%
Production:						
Natural gas (million cubic feet)	5,547	5,821	-5%	17,276	19,022	-9%
Oil and condensate (thousand barrels)	157	180	-13%	464	535	-13%
Natural gas liquids (thousand gallons)	7,321	6,263	17%	20,725	21,132	-2%
Total (million cubic feet equivalent)	7,535	7,796	-3%	23,021	25,251	-9%
Natural gas (million cubic feet per day)	61.0	64.7	-6%	62.8	69.4	-10%
Oil and condensate (thousand barrels per day)	1.7	2.0	-15%	1.7	2.0	-15%
Natural gas liquids (thousand gallons per day)	80.5	69.6	16%	75.4	77.1	-2%
Total (million cubic feet equivalent per day)	82.7	86.6	-5%	83.8	92.4	-9%
Average Sales Price:						
Natural gas (per thousand cubic feet)	$ 2.57	$ 4.50	-43%	$ 3.40	$ 4.35	-22%
Oil and condensate (per barrel)	$ 113.41	$ 96.30	18%	$ 112.53	$ 85.80	31%
Natural gas liquids (per gallon)	$ 1.28	$ 1.33	-4%	$ 1.38	$ 1.16	19%
Total (per thousand cubic feet equivalent)	$ 5.49	$ 6.65	-17%	$ 6.06	$ 6.06	0%
Summary of Financial Information:						
Operating expenses	$ 5,727	$ 5,652	1%	$ 18,626	$ 15,926	17%
Exploration expenses	$ 76	$ 14	443%	$ 133	$ 9,848	-99%
Depreciation, depletion and amortization	$ 11,710	$ 13,007	-10%	$ 36,203	$ 40,709	-11%
Impairment of natural gas and oil properties	$	$ 1,675	-100%	$	$ 1,786	-100%
General and administrative expenses	$ 1,226	$ 5,661	-78%	$ 5,778	$ 11,940	-52%
Other income (expense)	$ 42	$ (37)	-214%	$ (86)	$ (122)	-30%
Selected data per Mcfe:						
Lease operating expenses	$ 0.76	$ 0.73	4%	$ 0.81	$ 0.63	29%
General and administrative expenses	$ 0.16	$ 0.73	-78%	$ 0.25	$ 0.47	-47%
Depreciation, depletion and amortization of natural gas and oil properties	$ 1.53	$ 1.65	-7%	$ 1.55	$ 1.60	-3%

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

Natural Gas, Oil and Natural Gas Liquids (NGL) Sales and Production. We reported revenues of approximately $41.3 million for the three months ended March 31, 2012, compared to revenues of approximately $51.8 million for the three months ended March 31, 2011. This decrease of $10.5 million was principally attributable to a lower average equivalent sales price received for the period, slightly offset by our Vermilion 170 well which began producing in fiscal year 2012.

Our net natural gas production for the three months ended March 31, 2012 was approximately 61.0 Mmcfd, down from approximately 64.7 Mmcfd for the three months ended March 31, 2011. Net oil and condensate production for the comparable periods also decreased from approximately 2,000 barrels per day to approximately

1,700 barrels per day, and our NGL production increased from approximately 69,600 gallons per day to approximately 80,500 gallons per day. In total, equivalent production decreased from 86.6 Mmcfed to 82.7 Mmcfed.

Average Sales Prices. For the three months ended March 31, 2012, the average price of natural gas was $2.57 per thousand cubic feet (Mcf), the average price for oil and condensate was $113.41 per barrel and the average price for NGLs was $1.28 per gallon. For the three months ended March 31, 2011, the average price of natural gas was $4.50 per Mcf, the average price for oil and condensate was $96.30 per barrel and the average price for NGLs was $1.33 per gallon.

Operating Expenses. Lease operating expenses (LOE) for the three months ended March 31, 2012 were approximately $5.7 million, which included approximately $1.1 million in Louisiana state severance taxes. Lease operating expenses for the three months ended March 31, 2011 were also approximately $5.7 million, which included approximately $2.7 million in Louisiana state severance taxes.

Exploration Expense. We reported approximately $76,000 of exploration expense for the three months ended March 31, 2012, and $14,000 for the three months ended March 31, 2011. These costs relate to various geological and geophysical activities, seismic data and delay rentals.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the three months ended March 31, 2012 was approximately $11.7 million. For the three months ended March 31, 2011, we recorded approximately $13.0 million of depreciation, depletion and amortization. The decrease in depreciation, depletion and amortization was primarily attributable to a decrease in production from our Eloise North well, slightly offset by commencing production from Vermilion 170 in September 2011.

Impairment of Natural Gas and Oil Properties. For the three months ended March 31, 2012, no impairment was recognized on our properties. For the three months ended March 31, 2011, the Company recorded impairment expense of approximately $1.7 million related to certain offshore leases.

General and Administrative Expenses. General and administrative expenses for the three months ended March 31, 2012 and the three months ended March 31, 2011 were approximately $1.2 million and $5.7 million, respectively.

Major components of general and administrative expenses for the three months ended March 31, 2012 included approximately $0.3 million in State of Louisiana franchise taxes, $0.3 million in salaries and benefits, $0.4 million in accounting, tax, legal, engineering and other professional fees, $0.1 million in insurance costs, and $0.1 million related to board of director compensation.

Major components of general and administrative expenses for the three months ended March 31, 2011 included approximately $0.2 million in State of Louisiana franchise taxes, $4.7 million in salaries and benefits (of which $4.0 million is accrued bonuses), $0.5 million in accounting, tax, legal, engineering and other professional fees, $0.1 million in insurance costs, and $0.2 million related to the cost of expensing stock options and board of director compensation.

Nine Months Ended March 31, 2012 Compared to Nine Months Ended March 31, 2011

Natural Gas, Oil and Natural Gas Liquids (NGL) Sales and Production. We reported revenues of approximately $139.4 million for the nine months ended March 31, 2012, compared to revenues of approximately $153.1 million for the nine months ended March 31, 2011. This decrease of $13.7 million was principally attributable to a lower average equivalent sales price received for the period, as well as our Eloise North well which stopped producing in February 2011, slightly offset by our Vermilion 170 well which began producing on September 13, 2011.

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Our net natural gas production for the nine months ended March 31, 2012 was approximately 62.8 Mmcfd, down from approximately 69.4 Mmcfd for the nine months ended March 31, 2011. Net oil and condensate production for the comparable periods also decreased from approximately 2,000 barrels per day to approximately 1,700 barrels per day, and our NGL production decreased from approximately 77,100 gallons per day to approximately 75,400 gallons per day. In total, equivalent production decreased from 92.4 Mmcfed to 83.8 Mmcfed.

Average Sales Prices. For the nine months ended March 31, 2012, the average price of natural gas was $3.40 per thousand cubic feet (Mcf), the average price for oil and condensate was $112.53 per barrel and the average price for NGLs was $1.38 per gallon. For the nine months ended March 31, 2011, the average price of natural gas was $4.35 per Mcf, the average price for oil and condensate was $85.80 per barrel and the average price for NGLs was $1.16 per gallon.

Operating Expenses. Lease operating expenses (LOE) for the nine months ended March 31, 2012 were approximately $18.6 million, which included Louisiana state severance taxes of approximately $3.2 million. For the nine months ended March 31, 2011, we recorded lease operating expenses of approximately $15.9 million, which included approximately $3.9 million in Louisiana state severance taxes.

Exploration Expense. We reported approximately $0.1 million of exploration expense for the nine months ended March 31, 2012, related to various geological and geophysical activities, seismic data, and delay rentals. For the nine months ended March 31, 2011, we reported exploration expense of approximately $9.8 million. Of this amount, approximately $9.5 million related to our dry hole at Galveston Area 277L and the remaining $0.3 million related to various geological and geophysical activities, seismic data and delay rentals.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the nine months ended March 31, 2012 was approximately $36.2 million. For the nine months ended March 31, 2011, we recorded approximately $40.7 million of depreciation, depletion and amortization. The decrease in depreciation, depletion and amortization was primarily attributable to a decrease in production from our Eloise South and Eloise North wells, slightly offset by our Vermilion 170 well which began producing in September 2011.

Impairment of Natural Gas and Oil Properties. For the nine months ended March 31, 2012, no impairment was recognized on our properties. For the nine months ended March 31, 2011, we recorded impairment expense of approximately $1.8 million related to certain offshore leases.

General and Administrative Expenses. General and administrative expenses for the nine months ended March 31, 2012 and the nine months ended March 31, 2011 were approximately $5.8 million and $11.9 million, respectively.

Major components of general and administrative expenses for the nine months ended March 31, 2012 included approximately $0.6 million in State of Louisiana franchise taxes, $3.4 million in salaries and benefits (of which $1.5 million is accrued bonuses), $1.2 million in accounting, tax, legal, engineering and other professional fees, $0.3 million in insurance costs, and $0.3 million related to board of director compensation.

Major components of general and administrative expenses for the nine months ended March 31, 2011 included approximately $0.7 million in State of Louisiana franchise taxes, $8.0 million in salaries and benefits (of which $5.9 million is accrued bonuses), $1.2 million in accounting, tax, legal, engineering and other professional fees, $0.4 million in insurance costs, and $1.6 million related to the cost of expensing stock options and board of director compensation.

Other Income (Expense). We reported other expense of approximately $86,000 for the nine months ended March 31, 2012, compared to other expense of $122,000 for the nine months ended March 31, 2011, both mainly attributable to commitment fees paid under our credit facility.

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Capital Resources and Liquidity

Cash From Operating Activities. Cash flows from operating activities provided approximately $56.6 million in cash for the nine months ended March 31, 2012 compared to $94.1 million for the same period in 2011. This decrease in cash provided by operating activities was mainly attributable to the timing of payments of the Company s obligations.

Cash From Investing Activities. Cash flows used in investing activities for the nine months ended March 31, 2012 were approximately $30.0 million, compared to using $56.8 million in investing activities for the nine months ended March 31, 2011. This decrease in cash used in investing activities was primarily attributable to decreased capital expenditures for drilling and developing wells in 2011.

Cash From Financing Activities. Cash flows used in financing activities for the nine months ended March 31, 2012 were approximately $16.7 million, compared to using approximately $9.7 million for the nine months ended March 31, 2011. This increase in cash used in financing activities was attributable to purchasing more shares of common stock during the nine months ended March 31, 2012 under our publicly announced share repurchase programs.

Capital Budget. Our capital expenditure budget for the next twelve months calls for us to invest approximately $176.1 million from cash on hand and operating cash flows, as follows:

We have budgeted to invest approximately $25 million to drill our Ship Shoal 134 (Eagle) prospect.

We have budgeted to invest approximately $25 million to drill our South Timbalier 75 (Fang) prospect.

We have budgeted to invest approximately $20 million to drill a wildcat exploration well in the Gulf of Mexico.

We have budgeted to invest approximately $82.5 million in Exaro Energy III LLC ($41.3 million of this was invested in April 2012).

We have budgeted to invest approximately $8.6 million in Alta Energy (remaining balance of $20 million commitment)

We have budgeted to invest approximately $15 million in an onshore shale oil play (remaining balance of $20 million commitment). Should the Company have exploration success with any of its exploration wells, our capital expenditure budget will be significantly increased.

The Company often reviews acquisitions and prospects presented to us by third parties and we may decide to invest in one or more of these opportunities. There can be no assurance that we will invest, or that any investment entered into will be successful. These potential investments are not part of our current capital budget and would require us to invest additional capital. Natural gas and oil prices continue to be volatile and our resources may be insufficient to fund any of these opportunities.

The Company views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, in addition to being a source of funds for potentially higher rate of return natural gas and oil exploration investments. We believe these periodic natural gas and oil property sales are an efficient strategy to meet our cash and liquidity needs by providing us with immediate cash, which would otherwise take years to realize through the production lives of the fields sold. We have in the past and expect in the future to continue to rely heavily on the sales of assets to generate cash to fund our exploration investments and operations.

These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts are not successful in generating new discoveries, production, revenues and cash flows. Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of these property sales the

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Company s ability to collateralize bank borrowings is reduced which may increase our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

Natural Gas and Oil Reserves

The following table presents our estimated net proved natural gas and oil reserves at March 31, 2012 and June 30, 2011, based on reserve reports generated by William M. Cobb & Associates, Inc. (Cobb). The Company believes that having an independent and well respected third-party engineering firm prepare its reserve reports enhances the credibility of its reported reserve estimates. Management is responsible for the reserve estimate disclosures in this filing, and meets regularly with our independent third-party engineer to review these reserve estimates. The qualifications of the technical person at Cobb primarily responsible for overseeing the preparation of the Company s reserve estimates are set forth below.

Over 30 years of practical experience in the estimation and evaluation of reserves

A registered professional engineer in the State of Texas

Bachelor of Science Degree in Petroleum Engineering

Member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Cobb has informed us that the technical person primarily responsible for the reserve estimates meets or exceeds the education, training, and experience requirements set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain adequate and effective internal controls over the underlying data upon which reserves estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is communicated to our reservoir engineer quarterly, is confirmed when our third-party reservoir engineer holds technical meetings with geologists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in Internal Controls Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All data such as commodity prices, lease operating expenses, production taxes, field level commodity price differentials, ownership percentages, and well production data are updated in the reserve database by our third-party reservoir engineer and then analyzed by management to ensure that they have been entered accurately and that all updates are complete. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm prepares the independent reserve estimates and final report.

	Proved Reserves as of	
	March 31, 2012	**June 30, 2011**
Natural Gas (MMcf)	205,048	238,145
Oil, Condensate and Natural Gas Liquids (MBbls)	7,682	9,764
Total proved reserves (Mmcfe)	251,140	296,729
Pre-tax net present value ($000) (discounted at 10%)	$ 818,043	$ 981,041
Future income taxes, discounted at 10%	(220,059)	(263,906)

Standardized measure of discounted future net cash flows	$ 597,984	$ 717,135

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Our proved reserves as of March 31, 2012 are approximately 45.6 billion cubic feet equivalent (Bcfe) less than our proved reserves as of June 30, 2011. Of this amount, approximately 23.0 Bcfe is due to production during the nine months ended March 31, 2012, with the remaining 22.6 Bcfe due to a decrease of our Dutch and Mary Rose reserves as a result of new pressure information obtained, partially offset by an increase in our Ship Shoal 263 and Vermilion 170 reserves.

The line item Pre-tax net present value, discounted at 10% in the table above, is not intended to represent the current market value of the estimated natural gas and oil reserves we own. The pre-tax net present value of future cash flows attributable to our proved reserves as of March 31, 2012 was based on $3.72 per million British thermal units (MMbtu) for natural gas at the NYMEX, $98.33 per barrel of oil at the West Texas Intermediate Posting, and $60.85 per barrel of NGL, while the pre-tax net present value of future cash flows attributable to our proved reserves as of June 30, 2011 was based on $4.25 per MMbtu for natural gas at the NYMEX, $90.27 per barrel of oil at the West Texas Intermediate Posting, and $55.78 per barrel of NGLs, in each case before adjusting for basis, transportation costs and British thermal unit (BTU) content. The pre-tax net present value is a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K. The table above reconciles our calculation of pre-tax net present value to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that pre-tax net present value is an important non-GAAP financial measure used by analysts, investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially.

While we are reasonably certain of recovering our calculated reserves, the process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third-party engineer must project production rates and timing of development expenditures, as well as analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves has in the past varied from estimates and will most likely continue to vary in the future. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, our third party engineers may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company s board of directors approved a $100 million share repurchase program which concluded in October 2011. All shares were purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases were made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes.

For the nine months ended March 31, 2012, the Company purchased the below listed shares under its $100 million share repurchase program:

Period	Total Number Of Shares Purchased	Average Price Paid Per Share	Total Number Of Shares Purchased As Part of Publicly Announced $100 Million Program	Approximate Dollar Value of Shares That May Yet Be Purchased Under $100 Million Program
August 22 23, 2011	36,700	$ 54.91	1,922,141	$ 13.0 million
September 21 30, 2011	207,000	$ 55.64	2,129,141	$ 1.5 million
October 3, 2011	28,137	$ 54.09	2,157,278	

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$50 Million Share Repurchase Program

On September 28, 2011, the Company s Board of Directors approved the adoption of a $50 million share repurchase program, effective upon completion of purchases under the Company s $100 million share repurchase program. The repurchases will be subject to the same terms and conditions as repurchases made under the $100 million share repurchase program. For the nine months ended March 31, 2012, the Company purchased the below listed shares under its $50 million share repurchase program:

Period	Total Number Of Shares Purchased	Average Price Paid Per Share	Total Number Of Shares Purchased As Part of Publicly Announced $50 Million Program	Approximate Dollar Value of Shares That May Yet Be Purchased Under $50 Million Program
October 3 7, 2011	33,163	$ 54.38	33,163	$ 48.2 million
December 14, 2011	2,500	$ 57.21	35,663	$ 48.1 million

Additionally, in February 2012 the Company net-settled 45,000 stock options from two employees for a total of approximately $465,000. In total, under both share repurchase programs combined, as of April 30, 2012 the Company had purchased 2,192,941 shares of its common stock at an average cost per share of $46.49, and 45,000 stock options, for a total of approximately $102.4 million. As of April 30, 2012, the Company had 15,357,166 shares of common stock outstanding and no options.

Since inception, the Company has purchased 4,920,973 shares of stock and options at an average cost of $23.44 per share.

Credit Facility

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the Credit Agreement) to replace its expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and is available to fund the Company s exploration and development activities, as well as repurchase shares of common stock and to fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and effective November 1, 2011, a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of April 30, 2012, the Company was in compliance with all covenants and had no borrowings outstanding under the Credit Agreement.

Risk Factors

In addition to the other information set forth elsewhere in this Form 10-Q and in our annual report on Form 10-K, you should carefully consider the following factors when evaluating the Company. An investment in the Company is subject to risks inherent in our business. The trading price of the shares of the Company is affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in the Company may decrease, resulting in a loss.

We have no ability to control the market price for natural gas and oil. Natural gas and oil prices fluctuate widely, and a substantial or extended decline in natural gas and oil prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on the business, the results of operations and financial condition of the Company.

Our revenues, profitability and future growth depend significantly on natural gas and crude oil prices. Prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. We do not expect to hedge our production to protect against price

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decreases. Lower prices may also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

- Overall economic conditions.
- The domestic and foreign supply of natural gas and oil.
- The level of consumer product demand.
- Adverse weather conditions and natural disasters.
- The price and availability of competitive fuels such as LNG, heating oil and coal.
- Political conditions in the Middle East and other natural gas and oil producing regions.
- The level of LNG imports and any LNG exports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- Access to pipelines and gas processing plants.
- The loss of tax credits and deductions.

A substantial or extended decline in natural gas and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us.

We depend on the services of our Chairman and Chief Executive Officer, and implementation of our business plan could be seriously harmed if we lost his services.

We depend heavily on the services of Kenneth R. Peak, our Chairman and Chief Executive Officer. We do not have an employment agreement with Mr. Peak, and the proceeds from a $10.0 million key person life insurance policy on Mr. Peak may not be adequate to cover our losses in the event of Mr. Peak s death.

We are highly dependent on the technical services provided by JEX and could be seriously harmed if JEX terminated its services with us or became otherwise unavailable.

Because we employ no geoscientists or petroleum engineers, we are dependent upon JEX for the success of our natural gas and oil exploration projects and expect to remain so for the foreseeable future. Highly qualified explorationists and engineers are difficult to attract and retain. As a result, the loss of the services of JEX could have a material adverse effect on us and could prevent us from pursuing our business plan. Additionally, the loss by JEX of certain explorationists could have a material adverse effect on our operations as well. We have historically entered into agreements with JEX and its affiliates when we purchase prospects from JEX and its affiliates that specify the terms and conditions of purchase.

Our ability to successfully execute our business plan is dependent on our ability to obtain adequate financing.

Our business plan, which includes participation in 3-D seismic shoots, lease acquisitions, the drilling of exploration prospects and producing property acquisitions, has required and is expected to continue to require substantial capital expenditures. We may require additional financing to fund our planned growth. Our ability to raise additional capital will depend on the results of our operations and the status of various capital and industry markets at the time we seek such capital. Accordingly, additional financing may not be available to us on acceptable terms, if at all. In the event additional capital resources are unavailable, we may be required to curtail our exploration and development activities or be forced to sell some of our assets in an untimely fashion or on less than favorable terms.

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It is difficult to quantify the amount of financing we may need to fund our planned growth. The amount of funding we may need in the future depends on various factors such as:

- Our financial condition.
- The prevailing market price of natural gas and oil.
- The type of projects in which we are engaging.
- The lead time required to bring any discoveries to production.

We frequently obtain capital through the sale of our producing properties.

The Company, since its inception in September 1999, has raised approximately $524 million from various property sales. These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts are not successful in generating new discoveries, production, revenues and cash flows. Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of these property sales the Company s ability to collateralize bank borrowings is reduced which increases our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

We assume additional risk as Operator in drilling high pressure and high temperature wells in the Gulf of Mexico.

COI, a wholly-owned subsidiary of the Company, was formed for the purpose of drilling and operating exploration wells in the Gulf of Mexico. Drilling activities are subject to numerous risks, including the significant risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. Drilling costs could be significantly higher if we encounter difficulty in drilling offshore exploration wells. The Company s drilling operations may be curtailed, delayed, canceled or negatively impacted as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or we may not recover all or any of our investment. The risk of significant cost overruns, curtailments, delays, inability to reach our target reservoir and other factors detrimental to drilling and completion operations may be higher due to our inexperience as an operator.

Additionally, we use turnkey contracts that may cost more than non-turnkey drilling contracts at daily rates. Should our contracts come off turnkey or should such turnkey contracts be terminated by the turnkey drilling contractor (under certain conditions), our drilling costs could be significantly higher.

We rely on third-party operators to operate and maintain some of our production platforms, pipelines and processing facilities and, as a result, we have limited control over the operations of such facilities. The interests of an operator may differ from our interests.

We depend upon the services of third-party operators to operate production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. We have limited influence over the conduct of operations by third-party operators. As a result, we have little control over how frequently and how long our production is shut-in when production problems, weather and other production shut-ins occur. Poor performance on the part of, or errors or accidents attributable to, the operator of a project in which we participate may have an adverse effect on our results of operations and financial condition. Also, the interest of an operator may differ from our interests.

Repeated production shut-ins can possibly damage our well bores.

Our well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production at our Eugene Island 11 platform, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill additional wells.

Concentrating our capital investment in the Gulf of Mexico increases our exposure to risk.

Our capital investments are primarily focused in offshore Gulf of Mexico exploration prospects, which may result in a total loss of our investment. Furthermore, even our productive wells may not result in profitable operations.

Gulf of Mexico exploration efforts have been undertaken for over 60 years and remaining prospects are at deeper horizons that are more expensive to drill and often in much deeper water depths. Accordingly, as a result, a number of companies have shifted their focus to onshore shale plays. The Company s continuing focus on the Gulf of Mexico will result in significant dry hole costs, perhaps in excess of $30 million for one well, which significantly concentrates and increases our risk profile.

Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Further, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.

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In order to prepare these estimates, our independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value.

The Company s reserves and revenues are primarily concentrated in one field.

Approximately 79% of our proved reserves are assigned to our Dutch and Mary Rose discoveries which have ten producing well bores concentrated in one reservoir on one field, and are producing through two production platforms. Reserve assessments based on only ten well bores in one reservoir are subject to significantly greater risk of being shut-in for a variety of weather, platform and pipeline difficulties. In addition, the risk of a downward revision in our reserve estimates is also greater.

We rely on the accuracy of the estimates in the reservoir engineering reports provided to us by our outside engineer.

We have no in house reservoir engineering capability, and therefore rely on the accuracy of the periodic reservoir reports provided to us by our independent third-party reservoir engineer. If those reports prove to be inaccurate, our financial reports could have material misstatements. Further, we use the reports of our independent reservoir engineer in our financial planning. If the reports of the outside reservoir engineer prove to be inaccurate, we may make misjudgments in our financial planning.

Exploration is a high risk activity, and our participation in drilling activities may not be successful.

Our future success largely depends on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the significant risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Unexpected drilling conditions.
- Blowouts, fires or explosions with resultant injury, death or environmental damage.
- Pressure, temperature or other irregularities in formations.
- Equipment failures and/or accidents caused by human error.
- Tropical storms, hurricanes and other adverse weather conditions.
- Compliance with governmental requirements and laws, present and future.

Shortages or delays in the availability of drilling rigs and the delivery of equipment.

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Our turnkey drilling contracts reverting to a day rate contract or our turnkey contractor electing to terminate the turnkey contract would significantly increase the cost and risk to the Company.

Problems at third-party operated platforms, pipelines and gas processing facilities over which we have no control.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would materially and adversely affect our future cash flows and results of operations.

In addition, as a successful efforts company, we choose to account for unsuccessful exploration efforts (the drilling of dry holes) and seismic costs as a current expense of operations, which immediately impacts our earnings. Significant expensed exploration charges in any period would materially adversely affect our earnings for that period and cause our earnings to be volatile from period to period.

Production activities in the Gulf of Mexico increase our susceptibility to pollution and natural resource damage.

A blowout, rupture or spill of any magnitude would present serious operational and financial challenges. Most of the Company s operations are on the Gulf of Mexico shelf in water depths less than 200 feet and less than 50 miles from the coast. Such proximity to the shore-line increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth s atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions in the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including countries in the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The Environmental Protection Agency (the EPA) has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. Beyond measuring and reporting, the EPA issued an Endangerment Finding under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules at a subsequent date.

Several decisions have been issued by courts that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

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Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the natural gas and condensate that we produce.

The natural gas and oil business involves many operating risks that can cause substantial losses and our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The natural gas and oil business involves a variety of operating risks, including:

- Blowouts, fires and explosions.
- Surface cratering.
- Uncontrollable flows of underground natural gas, oil or formation water.
- Natural disasters.
- Pipe and cement failures.
- Casing collapses.
- Stuck drilling and service tools.
- Reservoir compaction.
- Abnormal pressure formations.
- Environmental hazards such as natural gas leaks, oil spills, pipeline ruptures or discharges of toxic gases.
- Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
- Repeated shut-ins of our well bores could significantly damage our well bores.
- Required workovers of existing wells that may not be successful.

If any of the above events occur, we could incur substantial losses as a result of:

- Injury or loss of life.
- Reservoir damage.
- Severe damage to and destruction of property or equipment.
- Pollution and other environmental damage.
- Clean-up responsibilities.
- Regulatory investigations and penalties.
- Suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances, operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If we were to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect our ability to conduct operations. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. We may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Not hedging our production may result in losses.

Due to the significant volatility in natural gas prices and the potential risk of significant hedging losses if our production should be shut-in during a period when NYMEX natural gas prices increase, our policy is to hedge only through the purchase of puts. By not hedging our production, we may be more adversely affected by declines in natural gas and oil prices than our competitors who engage in hedging arrangements.

Our ability to market our natural gas and oil may be impaired by capacity constraints and equipment malfunctions on the platforms, gathering systems, pipelines and gas plants that transport and process our natural gas and oil.

All of our natural gas and oil is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or our transportation capacity is materially restricted or is unavailable in the future, our ability to market our natural gas or oil could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on our financial condition and results of operations. Further, repeated shut-ins of our wells could result in damage to our well bores that would impair our ability to produce from these wells and could result in additional wells being required to produce our reserves.

We may not have title to our leased interests and if any lease is later rendered invalid, we may not be able to proceed with our exploration and development of the lease site.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is to not incur the expense of retaining title lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of JEX and others to perform the field work in examining records in the appropriate governmental, county or parish clerk s office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well the operator of the well will typically obtain a preliminary title review of the drillsite lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may not have been cured by the operator of such wells. It does happen, from time to time, that the examination made by title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect. It may also happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Competition in the natural gas and oil industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with a broad range of natural gas and oil companies in our exploration and property acquisition activities. We also compete for the equipment and labor required to operate and to develop these properties. Many of our competitors have substantially greater financial resources than we do. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties. Further, they may be able to evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil and to acquire additional properties in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating for a much longer time than we have and have substantially larger staffs. We may not be able to compete effectively with these companies or in such a highly competitive environment.

Proposed United States federal budgets and pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

In February 2009, the federal administration released its budget proposals for 2010, which included numerous proposed tax changes. In April 2009, legislation was introduced to further these objectives and in February 2010, the federal administration released similar budget proposals for 2011. The proposed budgets and legislation would repeal many tax incentives and deductions that are currently used by oil and gas companies in the United States and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law, taxes on the E&P industry would increase, which could have a negative impact on our results of operations and cash flows. Although these proposals initially were made in 2009, none have become law. It is still, however, the federal administration s stated intention to enact legislation to repeal tax incentives and deductions and impose new taxes on oil and gas companies.

We are subject to complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment. Failure to comply with such rules and regulations could result in substantial penalties and have an adverse effect on us. These laws and regulations:

- Require that we obtain permits before commencing drilling.
- Restrict the substances that can be released into the environment in connection with drilling and production activities.
- Limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas.
- Require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain only limited insurance coverage for sudden and accidental environmental damages. Accordingly, we may be subject to liability, or we may be required to cease production from properties in the event of environmental damages. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed and any such changes could have an adverse effect on our business and results of operations.

Our operations in the Gulf of Mexico have been and may continue to be adversely affected by changes in laws and regulations which have occurred and are expected to continue to occur as a result of the Deepwater Horizon Incident.

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon was engaged in drilling operations for another operator and sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill. As a result, the Department of the Interior issued additional safety and performance

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standards as well as rigorous monitoring and testing requirements for offshore drilling. In addition, various Congressional committees began pursuing legislation to regulate drilling activities, establish safety requirements and increase liability for oil spills.

We continue to monitor legislative and regulatory developments, including the Drilling Safety Rule and the Workforce Safety Rule issued by the Department of the Interior. However, the full legislative and regulatory response to the incident is not fully known. An expansion of safety and performance regulations or an increase in liability for drilling activities will have one or more of the following impacts on our business:

- Increase the costs of drilling exploratory and development wells.
- Cause delays in, or preclude, the development of projects in the Gulf of Mexico.
- Result in longer time periods to obtain permits.
- Result in higher operating costs.
- Increase or remove liability caps for claims of damages from oil spills.
- Limit our ability to obtain additional insurance coverage on commercially reasonable terms to protect against any increase in liability.

Any of the above factors may result in a reduction of our cash flows, profitability, and the fair value of our properties.

New regulatory requirements and permitting procedures have significantly delayed our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the Deepwater Horizon Incident in the Gulf of Mexico, a series of Notices to Lessees (NTLs) were issued which imposed new regulatory requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new regulatory requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.
- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system (SEMS) in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

Since the adoption of these new regulatory requirements, BOEM has been taking much longer periods of time to review and approve permits for new wells. Due to the extremely slow pace of permit review and approval, the BOEM may now take four months or longer to approve applications for drilling permits that were previously approved in less than 30 days. The new rules also increase the cost of preparing each permit application and will increase the cost of each new well.

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The BSEE has implemented much more stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. They are responsible for leading the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well design and workplace safety to corporate accountability.

One of the many reforms includes implementing a SEMS program. This program requires operators to identify, address, and manage safety and environmental hazards during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. Failure to implement an effective and robust SEMS program by November 15, 2011 or failure to comply with the program may force us to cease operations in the Gulf of Mexico.

Additionally, the OCS Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and a periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills, or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production, and pipeline safety. Upon detecting a violation, the inspector issues an Incident of Noncompliance (INC) to the operator and uses one of two main enforcement actions (warning or shut-in), depending on the severity of the violation. If the violation is not severe or threatening, a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility. The violation must be corrected before the operator is allowed to resume the activity in question.

In addition to the enforcement actions specified above, the BSEE can assess a civil penalty of up to $35,000 per violation per day if: 1) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or 2) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

It is customary in our industry to recover natural gas and oil from shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations using water, sand and other additives pumped under high pressure into the formation. We intend to use hydraulic fracturing as a means to increase the productivity of the onshore wells that we drill and complete.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states, including Pennsylvania, Texas, Colorado, Montana, New Mexico and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Additionally, the EPA has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and is completing the process of drafting guidance documents related to this newly asserted regulatory authority. There are also certain governmental reviews either underway or being proposed that focus on shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities. The EPA has published proposed New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that, if adopted as proposed, would amend existing NSPS and NESHAP standards for oil and gas facilities as well as create new NSPS standards for oil and gas production, transmission and distribution facilities. The EPA has also proposed regulations focused on reducing emissions of certain air pollutants by the oil and gas industry, including volatile organic compounds, sulfur dioxide and certain air toxics.

Certain environmental and other groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

We do not control the activities on properties we do not operate.

Other companies may from time to time drill, complete and operate properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including:

- Timing and amount of capital expenditures.
- The operator s expertise and financial resources.
- Approval of other participants in drilling wells.
- Selection of technology.

We are highly dependent on our management team, JEX, our exploration partners and third-party consultants and engineers, and any failure to retain the services of such parties could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. We are highly dependent on the services provided by JEX. The loss of key members of our management team, JEX or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves.
- Exploration potential.

Future natural gas and oil prices.

Operating costs.

Potential environmental and other liabilities and other factors.

Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are necessarily inexact and their accuracy inherently uncertain and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

Future acquisitions could pose additional risks to our operations and financial results, including:

Problems integrating the purchased operations, personnel or technologies.

Unanticipated costs.

Diversion of resources and management attention from our exploration business.

Entry into regions or markets in which we have limited or no prior experience.

Potential loss of key employees of the acquired organization.

Low interest rates put us at a competitive disadvantage compared to our peers.

As of March 31, 2012, we had approximately $159.9 million in cash and no debt. The overnight T-bill investment rate for the nine months ended March 31, 2012 averaged approximately 0.01%, which would generate investment income for the quarter of approximately $4,000. This level of interest income is insufficient to pay the administrative costs associated with tracking and recording the income earned. For this reason we keep all of our cash in non-interest bearing accounts which are backed by the full faith of the U.S. Government. Companies which borrow money are able to do so at extremely low rates and thereby may benefit from today s low level of interest rates.

Anti-takeover provisions of our certificate of incorporation, bylaws and Delaware law could adversely effect a potential acquisition by third-parties that may ultimately be in the financial interests of our stockholders.

Our Certificate of Incorporation, Bylaws and the Delaware General Corporation Law contain provisions that may discourage unsolicited takeover proposals. These provisions could have the effect of inhibiting fluctuations in the market price of our common stock that could result from actual or rumored takeover attempts, preventing changes in our management or limiting the price that investors may be willing to pay for shares of common stock.

The Company adopted a Stockholders Rights Plan (the Plan) in September 2008, which terminated September 30, 2011, that was designed to ensure that all stockholders of the Company receive fair value for their shares of common stock in a proposed takeover of the Company and to guard against coercive takeover tactics to gain control of the Company. The Company has not adopted, and does not currently intend to adopt, a similar plan following the expiration of the Plan. However, our organizational documents, among other things, authorize the board of directors to:

Designate the terms of and issue new series of preferred stock.

Limit the personal liability of directors.

Limit the persons who may call special meetings of stockholders.

Prohibit stockholder action by written consent.

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Establish advance notice requirements for nominations for election of the board of directors and for proposing matters to be acted on by stockholders at stockholder meetings.

Require us to indemnify directors and officers to the fullest extent permitted by applicable law.

Impose restrictions on business combinations with some interested parties.

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

Interest Rate and Credit Rating Risk. As of April 30, 2012, we had no long-term debt subject to the risk of loss associated with movements in interest rates.

As of March 31, 2012, we had approximately $159.9 million in cash and cash equivalents, all of which was held in non-interest bearing accounts. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of March 31, 2012, an immediate 10% change in interest rates is not expected to have a material effect on our near-term financial condition or results of operations.

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas and oil production. Realized commodity prices received for our production are the spot prices applicable to natural gas and crude oil. Prices received for natural gas and oil are volatile and unpredictable and are beyond our control. For the nine months ended March 31, 2012, a 10% fluctuation in the prices received for natural gas and oil production would impact our revenues by approximately $13.9 million. It could also lead to impairment of our natural gas and oil properties.

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

Kenneth R. Peak, our Chairman and Chief Executive Officer, together with our Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the Company s disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of March 31, 2012. Based upon that evaluation, the Company s management concluded that, as of March 31, 2012, the Company s disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and to ensure that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chairman and Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company s internal control over financial reporting that occurred during the fiscal quarter ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1A. ***Risk Factors***

The description of the risk factors associated with the Company set forth under the heading Risk Factors in Item 2 of Part I, Management s Discussion and Analysis of Financial Condition and Results of Operations, of this Form 10-Q is incorporated into this Item 1A by reference and supersedes the description of risk factors set forth under the heading Risk Factors in Item 1 of Part I of our annual report on Form 10-K.

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

(c) Issuer Purchases of Equity Securities

The description of repurchases made by the Company set forth under the heading Share Repurchase Program in Item 2 of Part I, Management s Discussion and Analysis of Financial Condition and Results of Operations, of this Form 10-Q is incorporated into this Item 2 by reference.

Item 5. Other Information

On September 30, 2008, the Company adopted the Plan which expired on September 30, 2011. The Plan was designed to ensure that all stockholders of Contango receive fair value for their shares of common stock in the event of any proposed takeover of Contango and to guard against the use of partial tender offers or other coercive tactics to gain control of Contango without offering fair value to all of Contango s stockholders. The Plan was not intended, nor did it operate, to prevent an acquisition of Contango on terms that were favorable and fair to all stockholders. Upon expiration of the Plan, the Company did not adopt, and does not currently intend to adopt, a similar plan.

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Item 6. ***Exhibits***

(a) Exhibits:

The following is a list of exhibits filed as part of this Form 10-Q. Where so indicated by a footnote, exhibits, which were previously filed, are incorporated herein by reference.

Exhibit Number	Description
3.1	Certificate of Incorporation of Contango Oil & Gas Company. (1)
3.2	Bylaws of Contango Oil & Gas Company. (1)
3.3	Agreement of Plan of Merger of Contango Oil & Gas Company, a Delaware corporation, and Contango Oil & Gas Company, a Nevada corporation. (1)
3.4	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company. (2)
4.1	Facsimile of common stock certificate of Contango Oil & Gas Company. (3)
10.1	Second Amended and Restated Credit Agreement dated as of October 1, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association, as Administrative Agent and Letter of Credit Issuer, together with First Amendment to Second Amended and Restated Credit Agreement dated October 20, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association. (4)
10.2	Purchase and Sale Agreement between Juneau Exploration, L.P. and Contango Operators, Inc. dated October 1, 2010. (5)
10.3	First Amended and Restated Limited Liability Company Agreement dated as of March 31, 2012. (6)
10.4	Advisory Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., dated as of April 5, 2012. (7)
23.1	Consent of William M. Cobb & Associates, Inc.
31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive Data Files

Filed herewith.

1. Filed as an exhibit to the Company s report on Form 8-K, dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000.
2. Filed as an exhibit to the Company s report on Form 10-QSB for the quarter ended December 31, 2002, dated November 14, 2002, as filed with the Securities and Exchange Commission.
3. Filed as an exhibit to the Company s Form 10-SB Registration Statement, as filed with the Securities and Exchange Commission on October 16, 1998.
4. Filed as an exhibit to the Company s report on Form 8-K, dated October 20, 2010, as filed with the Securities and Exchange Commission on October 25, 2010.
5. Filed as an exhibit to the Company s report on Form 10-Q for the quarter ended September 30, 2010, dated November 9, 2010, as filed with the Securities and Exchange Commission.
6. Filed as an exhibit to the Company s report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012.

7. Filed as an exhibit to the Company s report on Form 8-K, dated as of April 10, 2012, as filed with the Securities and Exchange Commission on April 11, 2012.

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SIGNATURES

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

		CONTANGO OIL & GAS COMPANY
Date: May 9, 2012	By:	/s/ KENNETH R. PEAK **Kenneth R. Peak** **Chairman and Chief Executive Officer** **(Principal Executive Officer)**
Date: May 9, 2012	By:	/s/ SERGIO CASTRO **Sergio Castro** **Vice President, Chief Financial Officer,** **Treasurer and Secretary** **(Principal Financial Officer)**
Date: May 9, 2012	By:	/s/ YAROSLAVA MAKALSKAYA **Yaroslava Makalskaya** **Vice President, Controller and Chief Accounting Officer** **(Principal Accounting Officer)**