UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

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 **(State or other jurisdiction of incorporation or organization)**	**95-4079863** **(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 ☒ 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 ☐ 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	☐	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 ☒

The total number of shares of common stock, par value $0.04 per share, outstanding as of May 1, 2011 was 15,664,666.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY REPORT ON FORM 10-Q
FOR THE NINE MONTHS ENDED MARCH 31, 2011

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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.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	March 31, 2011	June 30, 2010
CURRENT ASSETS:		
Cash and cash equivalents	$ 80,060,707	$ 52,469,144
Accounts receivable:		
Trade receivables	44,914,288	41,938,567
Joint interest billings	5,179,499	11,758,980
Income taxes	958,781	5,410,577
Other receivables	360,943	3,164,604
Notes receivable	—	2,027,590
Prepaids and other current assets	3,876,405	3,103,927
Total current assets	135,350,623	119,873,389
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	581,961,464	540,215,841
Unproved properties	6,520,291	10,825,074
Furniture and equipment	256,389	276,817
Accumulated depreciation, depletion and amortization	(125,574,070)	(78,998,049)
Total property, plant and equipment, net	463,164,074	472,319,683
OTHER ASSETS:		
Cash and other assets held by affiliates	359,729	39,731
Other	522,323	32,944
Total other assets	882,052	72,675
TOTAL ASSETS	$ 599,396,749	$592,265,747

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, 2011	June 30, 2010
CURRENT LIABILITIES:		
Accounts payable	$ 2,844,500	$ 34,219,769
Royalties and working interests payable	34,315,288	30,774,444
Accrued liabilities	10,363,640	2,647,435
Joint interest advances	—	739,464
Accrued exploration and development	1,011,022	9,263,438
Income tax payable	2,777,181	843,755
Other current liabilities	554,721	—
Total current liabilities	51,866,352	78,488,305
DEFERRED TAX LIABILITY	129,526,872	131,290,992
ASSET RETIREMENT OBLIGATION	8,909,224	5,156,642
COMMITMENTS AND CONTINGENCIES (NOTE 7)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50,000,000 shares authorized, 20,135,107 shares issued and 15,664,666 outstanding at March 31, 2011, 19,982,563 shares issued and 15,684,666 outstanding at June 30, 2010	805,402	799,300
Additional paid-in capital	79,278,372	77,967,702
Treasury stock at cost (4,470,441 and 4,297,897 shares at March 31, 2011 and June 30, 2010, respectively)	(91,788,647)	(82,019,429)
Retained earnings	420,799,174	380,582,235
Total shareholders' equity	409,094,301	377,329,808
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$599,396,749	$592,265,747

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,		Nine Months Ended March 31,	
	2011	2010	2011	2010
REVENUES:				
Natural gas, oil and liquids sales	$55,323,793	$37,845,738	$161,660,362	$119,528,579
Total revenues	55,323,793	37,845,738	161,660,362	119,528,579
EXPENSES:				
Operating expenses	6,389,747	3,523,835	17,600,926	11,066,471
Exploration expenses	14,459	22,514,428	10,376,469	22,932,224
Depreciation, depletion and amortization	15,548,338	6,837,887	46,980,287	25,182,258
Impairment of natural gas and oil properties	1,674,502	735,553	1,786,439	735,553
General and administrative expenses	5,661,260	1,199,930	11,939,616	4,362,957
Total expenses	29,288,306	34,811,633	88,683,737	64,279,463
OTHER INCOME (EXPENSE):	(37,152)	539,676	(121,893)	526,717
NET INCOME FROM CONTINUING OPERATIONS				
BEFORE INCOME TAXES	25,998,335	3,573,781	72,854,732	55,775,833
Provision for income taxes	(9,202,097)	(1,589,755)	(26,457,424)	(21,093,875)
NET INCOME FROM CONTINUING OPERATIONS	16,796,238	1,984,026	46,397,308	34,681,958
DISCONTINUED OPERATIONS (NOTE 10)				
Discontinued operations, net of income taxes	—	(241,966)	1,107,388	(362,763)
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$16,796,238	$ 1,742,060	$ 47,504,696	$ 34,319,195
NET INCOME PER SHARE:				
Basic				
Continuing operations	$ 1.07	$ 0.13	$ 2.96	$ 2.19
Discontinued operations	$ —	$ (0.02)	$ 0.07	$ (0.02)
Total	$ 1.07	$ 0.11	$ 3.03	$ 2.17
Diluted				
Continuing operations	$ 1.07	$ 0.12	$ 2.95	$ 2.15
Discontinued operations	$ —	$ (0.01)	$ 0.07	$ (0.03)
Total	$ 1.07	$ 0.11	$ 3.02	$ 2.12
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	15,664,666	15,859,618	15,665,166	15,840,607
Diluted	15,666,917	16,162,989	15,728,661	16,160,215

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, 2011	Nine Months Ended March 31, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income from continuing operations	$ 46,397,308	$ 34,681,958
Plus income (loss) from discontinued operations, net of income taxes	1,107,388	(362,763)
Net income	47,504,696	34,319,195
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	46,980,287	25,182,258
Impairment of natural gas and oil properties	1,786,439	735,553
Exploration expenditures	10,159,433	22,261,487
Deferred income taxes	(1,764,120)	6,856,377
Gain on disposition of assets	(2,737,539)	(112,868)
Tax benefit from exercise/cancellation of stock options	(501,767)	(122,025)
Stock-based compensation	1,369,726	447,643
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable and other	(2,975,721)	14,736,771
Decrease (increase) in prepaids and insurance receivable	1,522,314	(491,322)
Increase in interest receivable	—	(874,410)
Decrease in accounts payable and advances from joint owners	(21,994,409)	(4,592,318)
Increase (decrease) in other accrued liabilities	7,760,922	(6,701,696)
Increase in income taxes payable	6,886,989	7,053,887
Other	142,102	—
Net cash provided by operating activities	94,139,352	98,698,532
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	(55,155,003)	(40,646,487)
Additions to furniture and equipment	(71,806)	(2,463)
Repayment of note receivable	2,027,590	—
Investment in affiliates	(3,600,096)	(619,029)
Net cash used in investing activities	(56,799,315)	(41,267,979)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Tax benefit from exercise/cancellation of stock options	501,767	122,025
Dividends	(6,213)	—
Purchase of common stock	(9,769,218)	(1,616,073)
Proceeds from exercised options, warrants and others	—	122,699
Debt issuance costs	(474,810)	—
Net cash used in financing activities	(9,748,474)	(1,371,349)
NET INCREASE IN CASH AND CASH EQUIVALENTS	27,591,563	56,059,204
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	52,469,144	44,371,324
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 80,060,707	$100,430,528
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for taxes, net	$ 27,648,290	$ 7,127,400
Cash paid for interest	$ 123,425	$ 187,671

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		Paid-in	Treasury	Retained	Total Shareholders'
	Shares	Amount	Capital	Stock	Earnings	Equity
Balance at June 30, 2010	15,684,666	$799,300	$77,967,702	$(82,019,429)	$380,582,235	$377,329,808
Treasury shares at cost	(20,000)	—	—	(865,816)	—	$ (865,816)
Expense of stock options	—	—	221,203	—	—	$ 221,203
Net income	—	—	—	—	18,941,020	$ 18,941,020
Balance at September 30, 2010	15,664,666	$799,300	$78,188,905	$(82,885,245)	$399,523,255	$395,626,215
Exercise of stock options	152,544	6,102	(6,102)	—	—	$ —
Tax benefit of exercising stock options	—	—	501,767	—	—	$ 501,767
Liability adjustment for stock options	—	—	(440,034)	—	—	$ (440,034)
Treasury shares at cost	(152,544)	—	—	(8,903,402)	—	$ (8,903,402)
Expense of stock options	—	—	1,033,836	—	—	$ 1,033,836
Dividend	—	—	—	—	(7,287,757)	$ (7,287,757)
Net income	—	—	—	—	11,767,438	$ 11,767,438
Balance at December 31, 2010	15,664,666	$805,402	$79,278,372	$(91,788,647)	$404,002,936	$392,298,063
Net income	—	—	—	—	16,796,238	$ 16,796,238
Balance at March 31, 2011	15,664,666	$805,402	$79,278,372	$(91,788,647)	$420,799,174	$409,094,301

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 presentation 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, 2010. The consolidated results of operations for the three and nine months ended March 31, 2011 are not necessarily indicative of the results that may be expected for the fiscal year ending June 30, 2011.

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. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, and any such impairment is charged to expense in the period. 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 during the nine months ended March 31, 2011 or 2010. 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. During the nine months ended March 31, 2011, we recognized an impairment of unproved properties of approximately $1.8 million, 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, 2011, the Company had approximately $80.1 million in cash and cash equivalents. Of this amount, approximately $11.7 million was invested in U.S. Treasury money market funds, $11.0 million was invested in overnight U.S. Treasury funds, and the remaining $57.4 million was 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 intercompany balances and transactions. Wholly-owned subsidiaries are fully 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.

Stock-Based Compensation. The Company applies the fair value based method to account 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 fair value of each award is estimated using the Black-Scholes option-pricing model. The Company classifies the benefit of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows.

The Company's 1999 Stock Incentive Plan expired in August 2009. There are 45,000 outstanding options issued under the plan which will be converted into securities if exercised prior to their expiration in September 2013. 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 stock-based awards to any officer or director during the nine months ended March 31, 2011. During the nine months ended March 31, 2010, the Company issued 25,000 options to a new employee with the following assumptions: (i) risk-free interest rate of 0.25 percent; (ii) expected life of five years; (iii) expected volatility of 35.43 percent and (iv) expected dividend yield of zero percent.

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. This accelerated vesting resulted in the Company immediately recognizing stock compensation expense of approximately $1.1 million.

Additionally, the Board authorized management to net-settle any outstanding stock options in cash. The option holder has 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. The initial liability of $0.4 million recognized as of December 31, 2010 did not exceed the amount of compensation expense which had been previously recognized in equity for the original award and did not result in additional compensation expense but a reduction in equity. The Company recognized additional compensation expense of $0.2 million for the three months ended March 31, 2011. The liability of $0.6 million is included in other current liabilities in the Company's balance sheet as of March 31, 2011.

The liability for the outstanding 45,000 stock options is based on the fair value of each award evaluated at the end of each quarter using the Black-Scholes option-pricing model. The following assumptions were used in calculating the liability for the 45,000 outstanding options as of March 31, 2011: (i) risk-free interest rate of 0.30 percent; (ii) expected life of 1.06 years; (iii) expected volatility of 28.19 percent and (iv) expected dividend yield of zero percent. To the extent that the liability exceeds the amount recognized at the end of the previous period, the difference is recognized as compensation cost for each period until the stock options are settled.

The accelerated vesting and modification affects no other terms or conditions of the options, including the number of outstanding options or exercise price. During the nine months ended March 31, 2011 and 2010, the Company recorded stock-based compensation charges of approximately $1.4 million (inclusive of the expense associated with the accelerated vesting) and $0.4 million, respectively, to general and administrative expense for restricted stock and option awards. These amounts do not reflect compensation actually received by the individuals, but rather represent expense recognized in the Company's consolidated financial statements that relate to option awards granted in previous fiscal years.

Recent Accounting Pronouncements

On January 1, 2011, we implemented certain provisions of Accounting Standards Update No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820) – Improving Disclosures about Fair Value Measurements" ("Update 2010-06"). Update 2010-06 requires entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our consolidated results of operations, financial position or cash flows.

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. We use the successful efforts method of accounting for our natural gas and oil activities.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

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, 2011 were ConocoPhillips Company, Shell Trading US Company, 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. Other Receivables

On February 24, 2010, a dredge contracted by the Army Corps of Engineers to dredge the Atchafalaya River Channel ruptured the Company's 20" pipeline that runs from our Eugene Island 11 gathering platform to the Eugene Island 63 platform where our pipeline joins a third-party pipeline that transports our production to shore. The pipeline was repaired and production resumed on March 31, 2010. The repairs were covered by our insurance policy, subject to a deductible. Of the amount of "other receivables" recorded in the Consolidated Balance Sheets as of March 31, 2011 and June 30, 2010, approximately $0.2 million and $3.1 million, respectively, relates to this incident.

6. 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, 2011			Three Months Ended March 31, 2010		
	Income	Weighted Average Shares	Per Share	Income	Weighted Average Shares	Per Share
Income from continuing operations	$16,796,238	15,664,666	$1.07	$1,984,026	15,859,618	$ 0.13
Discontinued operations, net of income taxes	—	15,664,666	—	(241,966)	15,859,618	(0.02)
Basic Earnings per Share:						
Net income attributable to common stock	$16,796,238	15,664,666	$1.07	$1,742,060	15,859,618	$ 0.11
Effect of Potential Dilutive Securities:						
Stock options, net of shares assumed purchased	—	2,251	—	—	303,371	—
Income from continuing operations	$16,796,238	15,666,917	$1.07	$1,984,026	16,162,989	$ 0.12
Discontinued operations, net of income taxes	—	15,666,917	—	(241,966)	16,162,989	(0.01)
Diluted Earnings per Share:						
Net income attributable to common stock	$16,796,238	15,666,917	$1.07	$1,742,060	16,162,989	$ 0.11

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

6. Net Income per Common Share (continued)

	Nine Months Ended March 31, 2011			Nine Months Ended March 31, 2010		
	Income	Weighted Average Shares	Per Share	Income	Weighted Average Shares	Per Share
Income from continuing operations	$46,397,308	15,665,166	$2.96	$34,681,958	15,840,607	$ 2.19
Discontinued operations, net of income taxes	1,107,388	15,665,166	0.07	(362,763)	15,840,607	(0.02)
Basic Earnings per Share:						
Net income attributable to common stock	$47,504,696	15,665,166	$3.03	$34,319,195	15,840,607	$ 2.17
Effect of Potential Dilutive Securities:						
Stock options, net of shares assumed purchased	—	63,495	—	—	319,093	—
Restricted shares	—	—	—	—	515	—
Income from continuing operations	$46,397,308	15,728,661	$2.95	$34,681,958	16,160,215	$ 2.15
Discontinued operations, net of income taxes	1,107,388	15,728,661	0.07	(362,763)	16,160,215	(0.03)
Diluted Earnings per Share:						
Net income attributable to common stock	$47,504,696	15,728,661	$3.02	$34,319,195	16,160,215	$ 2.12

Options to purchase 85,000 shares of common stock were outstanding as of March 31, 2010, but were not included in the computation of diluted earnings per share for the three and nine months ended March 31, 2010. These options were excluded because either (i) the options' exercise price was greater than the average market price of the common shares, or (ii) application of the treasury method to in-the-money options made some of the options anti-dilutive.

7. Commitments and Contingencies

Contango pays delay rentals on its offshore leases and leases its office space and certain other equipment. In November 2010, the Company expanded its office space and extended its office lease agreement through December 31, 2015. As of March 31, 2011, minimum future lease payments for our fiscal years are as follows:

	Remainder of FY 2011	2012	2013	2014	2015	2016	Total
Delay rentals	$ 246,759	$499,897	$499,897	$329,785	$ 71,825	$ —	$1,648,163
Office space	57,720	233,460	238,622	243,782	248,942	125,761	1,148,287
Other equipment	2,584	10,335	10,335	9,775	—	—	33,029
Total	$ 307,063	$743,692	$748,854	$583,342	$320,767	$125,761	$2,829,479

Additionally, the Company has committed to invest up to $20 million over the next two years, in a joint venture that will acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

8. 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 the expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and will be available to fund the Company's offshore Gulf of Mexico 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 a commitment fee of 0.375% will be paid on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of March 31, 2011, the Company was in compliance with all covenants and had no amounts outstanding under the Credit Agreement.

9. Related Party Transactions

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.

The Company's wholly-owned subsidiary, Conterra Company ("Conterra"), entered into a joint venture with Patara Oil & Gas LLC ("Patara"), a privately held oil and gas company as of October 1, 2009, 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.

In March 2006, Contango Offshore Exploration LLC ("COE") executed a Promissory Note (the "COE Note") to the Company to finance its share of development costs in Grand Isle 72. The COE Note was payable upon demand and carried an annual interest rate of 10%. As of May 31, 2010, COE owed the Company $4.3 million under the COE Note, and owed an additional $1.6 million in accrued and unpaid interest. Effective June 1, 2010, COE was dissolved and the Company 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. This $2.0 million is reflected as a note receivable in the Consolidated Balance Sheet of the Company as of June 30, 2010. The note receivable was paid in full on October 27, 2010.

10. Disposition of Contango ORE, Inc.

On September 29, 2010, Contango ORE, Inc. ("CORE"), then a wholly-owned subsidiary of the Company, 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 1,566,367 shares of its common stock to the Company in addition to the 100 shares which the Company held prior to that date. 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, 2011, the assets and liabilities of Contango Mining were excluded from the Company's financial statements. The assets and liabilities of the Contango Mining included in the Company's balance sheet as of March 31, 2011 and June 30, 2010 were as follows:

	March 31, 2011	June 30, 2010
Cash	$ —	$ —
Other current assets	—	233,268
Mineral properties	—	1,008,886
Current liabilities	—	(511,156)

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

Results of operations of Contango Mining for the eleven months ended November 30, 2010 and for each of the previous periods are included in discontinued operations in the Company's Statement of Operations. The summarized financial results for discontinued operations for the three and nine months ended March 31, 2011 and 2010 were as follows:

	Three Months Ended March 31,		Nine months ended March 31,	
	2011	2010	2011	2010
Gain from disposition of assets	$ —	$ —	$2,737,539	$ —
Exploration expenses	—	(241,896)	(983,280)	(402,058)
General and administrative expenses	—	(70)	(154,238)	(16,755)
Gain (loss) before income taxes	$ —	$(241,966)	$1,600,021	$(418,813)
Benefit (provision) for income taxes	—		(492,633)	56,050
Gain (loss) from discontinued operations, net of income taxes	$ —	$(241,966)	$1,107,388	$(362,763)

The Gain from disposition of assets included in the Gain (loss) from discontinued operations represents the difference between $7.3 million, the fair value of the shares of CORE distributed to the Company's shareholders, and the historical value of the assets and liabilities transferred to CORE on or subsequent to November 29, 2010. The Company incurred approximately $2.2 million of cumulative losses from October 2009, the inception of Contango Mining to the effective date of the spin-off.

11. Income Taxes

The Company's income tax provision consists of the following:

	Three Months Ended March 31,		Nine Months Ended March 31,	
	2011	2010	2011	2010
Current income tax expense (benefit)	$10,230,343	$(3,079,228)	$28,714,176	$14,181,448
Deferred income tax expense (benefit)	(1,028,246)	4,668,983	(1,764,120)	6,856,377
Total income tax expense	$ 9,202,097	$ 1,589,755	$26,950,056	$21,037,825

12. Subsequent Events

On April 25, 2011, the Company's Board of Directors approved the sale of all of the Company's onshore assets in Texas for an aggregate purchase price of $40.0 million. These properties include: (i) our 90% working interest (72% net revenue interest) and subsequent 5% overriding royalty interest in the 21 wells drilled in Panola County, Texas under our joint venture with Patara; (ii) our 100% working interest (72.5% net revenue interest) in Rexer #1, drilled in south Texas; and (iii) an option to purchase up to 100% of our 100% working interest (73.6 % net revenue interest) in Rexer-Tusa #2, which the Company expects to spud in May 2011. The proposed sale to a third party is subject to the receipt of funding by the third party.

On April 12, 2011, the Company announced a commitment to invest up to $20 million over the next two years, in a joint venture that will acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets. As of May 6, 2011 no funds had been invested in this joint venture.

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, 2010, 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

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
- 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 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
- 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
- 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 primarily offshore in the Gulf of Mexico. Contango Operators, Inc. (“COI”), our wholly-owned subsidiary, acts as operator on certain offshore 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 our offshore Gulf of Mexico prospects. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. COI drills and operates our offshore 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 offshore exploration activities. Since its inception, the Company has sold approximately $484 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.

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 and Federal Deepwater Moratorium

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 resulting leak caused a significant oil spill. In May 2010, in response to the incident, the President of the United States announced a six-month moratorium on drilling in the deepwater Gulf of Mexico ("Federal Deepwater Moratorium" or the "Moratorium"). Under the Federal Deepwater Moratorium, no new drilling, including sidetracks and bypasses of wells, was allowed in water depths greater than 500 feet. For operators such as Contango that operate in less than 500 feet of water, new, more restrictive requirements have been implemented on permitting activities on the Outer Continental Shelf.

During the quarter ended September 30, 2010, the Outer Continental Shelf Safety Oversight Board, established by the Secretary of the Interior, issued its recommendations for the strengthening of permitting, inspections, enforcement and environmental stewardship. In addition, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) developed an implementation plan for the recommendations, many of which are already underway or planned.

On September 30, 2010, the Department of the Interior announced two new rules (The Drilling Safety Rule and the Workplace Safety Rule) that are intended to improve drilling safety by strengthening requirements for safety equipment, well control systems, and blowout prevention practices on offshore oil and gas operations, and improve workplace safety. The Secretary of the Interior lifted the Moratorium on October 12, 2010.

The Deepwater Horizon incident is likely to have a significant and lasting effect on the US offshore energy industry, and will likely result in a number of fundamental changes, including heightened regulatory scrutiny, more stringent operating and safety standards, changes in equipment requirements and the availability and cost of insurance, as well as increased politicization of the industry. These changes may result in increases in our operating and development costs and extend project development timelines because of new regulatory requirements. There may be other impacts of which we are not aware at this time.

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.

While the Company renewed its energy package and insurance policies in January 2011 at rates similar to the prior year, 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. This protection consists of $75 million of well control, pollution cleanup and consequential damages coverage; $150 million of additional pollution cleanup and consequential damages coverage, which also covers third party personal injury and death; and $150 million of 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 with the BOEMRE. Our response team is trained annually and is tested through annual spill drills given by the BOEMRE. 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. The Company's spill program is put into motion by notifying O'Brien's that we have an emergency. While the Company focuses 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 LA. The CGA equipment stockpile is available to serve member oil spill response needs including blowouts; open seas, near shore and shallow water skimming; open seas and shoreline booming; communications; dispersants; boat spray systems to apply dispersants; wildlife rehabilitation; and a forward command center. CGA has retainers with an aerial dispersant company and a company that provides mechanical recovery equipment for spill responses. 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"). On September 30, 2010, the BOEMRE announced a final SEMS rule which became effective November 15, 2010.

The final SEMS rule includes the following 13 mandatory elements of the American Petroleum Institute's Recommended Practice 75 (API RP 75):

- 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

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 and purchases exploration prospects generated by third-party independent companies. We do not have a written agreement with JEX which contractually obligates them to provide us with their services. Once we have purchased a prospect, however, from JEX or REX, 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.

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 May 1, 2011, Contango, through COI and REX, had an interest in 28 offshore leases. See “Offshore Properties” for additional information on our offshore properties.

Contango Operators, Inc

COI, a wholly-owned subsidiary of the Company, was formed for the purpose of drilling and operating wells in the Gulf of Mexico. Additionally, COI expects to acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, usually under a farm-out agreement, or similar agreement, with REX and/or JEX. COI may also acquire and operate significant working interests in offshore exploration and development opportunities under farm-in agreements with third parties.

The Company’s offshore operated production currently consists of 11 wells located on federal and State of Louisiana leases in the shallow waters of the Gulf of Mexico. These 11 wells produce via the following three platforms:

Eugene Island 11 Platform

As of May 1, 2011, the Company-owned and operated platform at Eugene Island 11 was processing approximately 41.0 Mmcfed, net to Contango. This platform was designed with a capacity of 500 million cubic feet per day (“Mmcfd”) and 6,000 barrels of oil per day (“bopd”). This platform services production from the Company’s four Mary Rose wells and Eloise North well, which are all located in State of Louisiana waters, as well as our Dutch #4 well and Dutch #5 well (previously Eloise South) (See “Other Activities” below), which are located in federal waters. From the Eugene Island 11 platform, the 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 the Eugene Island 63 auxiliary platform to third-party owned and operated on-shore processing facilities near Patterson, Louisiana.

In September 2010 the Company completed installing a companion platform adjacent to the Eugene Island 11 Platform (the “H-CMP Platform”). The H-CMP Platform, together with two newly laid pipelines, gives us the added flexibility to redirect a portion of the wells that produce to the Eugene Island 11 platform and send our natural gas and oil production to alternate markets. As of March 31, 2011, the Company has invested approximately $4.7 million to build and install the H-CMP Platform and pipelines.

Eugene Island 24 Platform

As of May 1, 2011, this third-party owned and operated production platform at Eugene Island 24 was processing approximately 24.3 Mmcfed, net to Contango. This platform 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.

Ship Shoal 263 Platform

As of May 1, 2011, the Company-owned and operated Ship Shoal 263 platform was processing approximately 11.7 Mmcfed, net to Contango. This platform was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services production from our Nautilus well which began producing in June 2010.

Effective October 1, 2010, the Company purchased an additional 7.5% working interest and 6.0% net revenue interest in Ship Shoal 263 for approximately $7.5 million from JEX. The Company now owns a 100% working interest and 80% net revenue interest in this well.

Other Activities

In February 2011, the Company spud its Offshore Gulf of Mexico wildcat exploration well, Vermilion 170 (Swimmy), and announced a discovery in March 2011. The Company's independent third party engineer estimates this well to have 8/8ths proved reserves of 48 billion cubic feet of natural gas and 1.2 million barrels of condensate, approximately 55 billion cubic feet equivalent ("Bcfe"), or 37.5 Bcfe net to Contango's 68% net revenue interest, inclusive of its investment in REX. Production is expected to begin in the fall of 2011 at an estimated rate of 15 million cubic feet equivalent per day ("Mmcfed"), net to Contango. Estimated net costs to Contango, to acquire, drill, complete, and bring this well to full production status are approximately $26.5 million.

Our Eloise North and Eloise South wells are currently both shut-in for remedial work. Our plan is to recomplete our Eloise South well uphole in the CibOp section as our Dutch #5 well. This recompletion is estimated to cost approximately $6.2 million, net to Contango. Our Eloise North well recently sanded-up and we are currently attempting to rework the well to restore production. If we are unsuccessful, our plan is to recomplete the well uphole in an upper Rob-L section at a net cost of approximately $0.8 million, net to Contango. We plan to have both of these wells on-line by mid-summer.

Effective February 24, 2011, the Company acquired the deep rights on Ship Shoal 134 from an independent third-party oil and gas company. On March 3, 2011, we submitted an exploration permit to drill our Eagle prospect on Ship Shoal 134, with an estimated cost to drill of approximately $20 million, net to Contango. We are hopeful that we will receive a permit to drill this prospect this summer, but due to hurricane season, we may not spud the well until the October/November 2011 time frame.

In September 2010, we spud our Galveston Area 277L prospect (His Dudeness), a wildcat exploration well in the Gulf of Mexico, and determined it was a dry hole. The Company invested approximately $9.5 million, including leasehold costs, to drill, plug and abandon this well.

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. The well is currently shut-in as the operator moves up hole to produce from another section. As of February 28, 2011, the well was producing at an 8/8ths rate of approximately 2.4 Mmcfed. 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 related entities in the Gulf of Mexico which were capable of producing natural gas or oil as of May 1, 2011:

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 (Eloise South)	26.86%	19.0%	Recompletion
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 (Eloise North)	36.90%	26.9%	Shut-in
Ship Shoal 263 (Nautilus)	100.00%	80.0%	Producing
West Delta 36 (produced via REX)	25.0%	20.0%	Producing

Leases. The following table sets forth the working interests owned by Contango and related entities in non-developed leases in the Gulf of Mexico as of May 1, 2011.

Area/Block	WI	Lease Date	Expiration Date
Contango Operators, Inc.:			
Viosca Knoll 383	(2)	Jun-06	Jun-11
S-L 19261	53.21%	Feb 07	Feb 12
S-L 19396	53.21%	Jun 07	Jun 12
Eugene Island 11	53.21%	Dec 07	Dec-12
East Breaks 369 (1)	(3)	Dec-03	Dec-13
East Breaks 370	65.63%	Dec-03	Dec-13
Galveston Area 248L	100.00%	Oct-09	Oct-14
Galveston Area 276L	100.00%	Oct-09	Oct-14
Galveston Area 277L (N/2 of NE/4)	100.00%	Oct-09	Oct-14
Galveston Area 277L (S/2 of NE/4)	100.00%	Oct-09	Oct-14
Galveston Area 338S	100.00%	Oct-09	Oct-14
Matagorda Island 607	100.00%	Nov-09	Nov-14
Matagorda Island 616	100.00%	Nov-09	Nov-14
Matagorda Island 617 (1)	100.00%	Nov-09	Nov-14
Ship Shoal 121	100.00%	Jul-10	Jul-15
Ship Shoal 122	100.00%	Jul-10	Jul-15
Vermilion 170	100.00%	Jul-10	Jul-15
East Breaks 366	65.63%	Nov-05	Nov-15
East Breaks 410	65.63%	Nov-05	Nov-15
Ship Shoal 134	100.00%	(4)	(4)
Republic Exploration LLC			
East Cameron 210	100.00%	Jun-09	Jun-14
South Timbalier 97	100.00%	Jun-09	Jun-14

(1) Dry Hole
(2) Farm-out. COI retains a 1.75% ORRI
(3) Farm-out. COI retains a 2.41% ORRI
(4) Acquired deep rights. Lease is held by production from shallow wells owned by others

Onshore Exploration and Properties

Conterra Company

Effective October 1, 2009, the Company's wholly-owned subsidiary, Conterra Company ("Conterra"), entered into a joint venture with Patara Oil & Gas LLC ("Patara"), a privately held oil and gas company, 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.

Under the terms of the joint venture agreement (the "Conterra Joint Venture Agreement"), Conterra agreed to fund 100% of the drilling and completion costs on 15 wells in exchange for 90% of the net revenues. The estimated 8/8ths cost is approximately $1.85 million per well. The average 8/8ths reserves per well are approximately 1.5 Bcfe (1.125 net Bcfe after a 25% royalty). In July 2010, the Conterra Joint Venture Agreement was amended to include an additional 15 wells, bringing the total number of wells to 30. Both parties have agreed to suspend further drilling after 21 wells due to the continuing weakness in natural gas prices. Assuming a $4.40/Mmbtu Henry Hub price for natural gas, $3.50/mcf is received by Conterra after basis, transportation and fuel charges. We estimate a minimum of seven years is required before we reach payout of our investment plus a 15% cash-on-cash rate of return, based on the $3.50/mcf price. Upon the Company achieving a 15% per annum cash-on-cash rate, the Company's net revenue interest converts into a 5% overriding royalty interest.

As of April 28, 2011, Conterra was producing at a rate of approximately 5.5 Mmcfed, net to Contango, from all 21 wells. As of March 31, 2011, we have invested approximately $42.9 million in Conterra and received approximately $7.1 million in revenues, for a net investment of $35.8 million. Our third party engineer has assigned us approximately 16.6 Bcfe of proved reserves as at March 31, 2011.

South Texas

In July 2010, the Company announced a discovery at its on-shore wildcat exploration well, (Rexer #1), in south Texas. The Company has a 100% working interest (72.5% net revenue interest) in this well before payout, and a 75% working interest (54.4% net revenue interest) after payout. Production began in October 2010 and as of May 1, 2011, was producing at a rate of approximately 1.6 Mmcfed, net to Contango. The Company plans in May 2011 to spud its second on-shore wildcat exploration well in south Texas, Rexer-Tusa #2. The Company has a 100% working interest (73.6% net revenue interest) in this well before payout, and a 75% working interest (55.2% net revenue interest) after payout. Total estimated costs to drill and complete this well are approximately $5.0 million, net to Contango.

Approval of Sale of Onshore Assets

On April 25, 2011, the Company's Board of Directors approved the sale of all of the Company's onshore assets in Texas for an aggregate purchase price of $40.0 million. These properties include: (i) our 90% working interest (72% net revenue interest) and subsequent 5% overriding royalty interest in the 21 wells drilled in Panola County, Texas under our joint venture with Patara; (ii) our 100% working interest (72.5% net revenue interest) in Rexer #1, drilled in south Texas; and (iii) an option to purchase up to 100% of our 100% working interest (73.6 % net revenue interest) in Rexer-Tusa #2, which the Company expects to spud in May 2011. The proposed sale to a third party is subject to the receipt of funding by the third party.

Alta Investments

On April 12, 2011, the Company announced a commitment to invest up $20 million over the next two years, in a joint venture that will acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets. Other participants include Alta Resources, LLC and Blackstone Capital Partners. As of May 6, 2011, no funds had been invested in this joint venture.

Contango ORE, Inc.

Contango Mining Company ("Contango Mining"), the predecessor to Contango ORE, Inc. ("CORE"), was formed on October 15, 2009 as a Delaware corporation registered to do business in Alaska for the purpose of engaging in exploration in the State of Alaska for (i) gold and associated minerals and (ii) rare earth elements. Contango Mining is a wholly-owned subsidiary of the Company and held leasehold interests in approximately 647,000 acres from the Tetlin Village Council, the council formed by the governing body for the Native Village of Tetlin, an Alaska Native Tribe ("Tetlin Lease") and held 12,000 acres in unpatented mining claims from the State of Alaska for the exploration of gold deposits and associated minerals (together with the Tetlin Lease, the "Gold Properties"). Contango Mining also held interests in and to 3,520 acres in unpatented Federal mining claims and 97,280 acres in unpatented mining claims from the State of Alaska for the exploration of rare earth elements (the "REE Properties", and together with the Gold Properties, the "Properties").

On November 29, 2010, CORE, then a wholly-owned subsidiary of the Company, acquired the assets and obligations of Contango Mining in exchange for its common stock which was distributed to the Company's stockholders of record as of October 15, 2010 on the basis of one share of common stock for each ten shares of the Company's common stock then outstanding. No fractional shares were issued, but a cash payment was made to shareholders with less than ten shares based upon the value established for CORE. The Company also contributed $3.5 million in cash to CORE immediately prior to the distribution.

The Company has obtained a valuation report from Avalon Development Corporation, a Fairbanks, Alaska-based mineral exploration consulting firm, of the value of the assets constituting the mineral properties owned or controlled by CORE. Based on that valuation report and the $3.5 million cash investment in CORE, the value of the assets contributed to CORE and distributed to Company shareholders was estimated to be approximately $0.46 per share of Contango Oil & Gas Company. The shares of CORE trade on the OTCBB under the symbol *CTGO*.

Employees

The Company outsources its human resources function to Insperity (formerly Administaff) and all of the Company's employees are co-employees of Insperity. The Company has eight employees.

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 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 to estimate the fair value 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, 2011 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $2.1 million, $4.5 million and $7.1 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 on a field-by-field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted net cash flows are lower than the unamortized capitalized cost, 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, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. 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.

Income Taxes. Income taxes are provided for the tax effects of transactions reported in the financial statements and consists 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.

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MD&A Summary Data

The table below sets forth revenue, expense and production data for the three and nine months ended March 31, 2011 and 2010.

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Change	Nine Months Ended March 31, 2011	Nine Months Ended March 31, 2010	Change
		($000)			($000)	
Revenues:						
Natural gas, oil and NGL sales	$55,324	$37,846	46%	$161,660	$119,529	35%
Total revenues	$55,324	$37,846	46%	$161,660	$119,529	35%
Production:						
Natural gas (million cubic feet)	6,434	4,043	59%	20,670	15,991	29%
Oil and condensate (thousand barrels)	184	102	80%	545	400	36%
Natural gas liquids (thousand gallons)	7,042	4,881	44%	23,358	18,685	25%
Total (million cubic feet equivalent)	8,544	5,352	60%	27,277	21,060	30%
Natural gas (million cubic feet per day)	71.5	44.9	59%	75.4	58.4	29%
Oil and condensate (thousand barrels per day)	2.0	1.1	82%	2.0	1.5	33%
Natural gas liquids (thousand gallons per day)	78.2	54.2	44%	85.2	68.2	25%
Total (million cubic feet equivalent per day)	94.7	59.2	60%	99.6	77.1	29%
Average Sales Price:						
Natural gas (per thousand cubic feet)	$ 4.43	$ 5.90	-25%	$ 4.28	$ 4.42	-3%
Oil and condensate (per barrel)	$ 96.13	$ 78.48	22%	$ 85.74	$ 73.51	17%
Natural gas liquids (per gallon)	$ 1.30	$ 1.22	7%	$ 1.13	$ 1.04	9%
Total (per thousand cubic feet equivalent)	$ 6.48	$ 7.07	-8%	$ 5.93	$ 5.68	4%
Operating expenses	$ 6,390	$ 3,524	81%	$ 17,601	$ 11,066	59%
Exploration expenses	$ 14	$22,514	-100%	$ 10,376	$ 22,932	-55%
Depreciation, depletion and amortization	$15,548	$ 6,838	127%	$ 46,980	$ 25,182	87%
Impairment of natural gas and oil properties	$ 1,675	$ 736	128%	$ 1,786	$ 736	143%
General and administrative expenses	$ 5,661	$ 1,200	372%	$ 11,940	$ 4,363	174%
Other income (expense)	$ (37)	$ 540	-107%	$ (122)	$ 527	-123%

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

Natural Gas, Oil and Natural Gas Liquids ("NGL") Sales. We reported revenues of approximately $55.3 million for the three months ended March 31, 2011, compared to revenues of approximately $37.8 million for the three months ended March 31, 2010. This increase in sales was principally attributable to increased natural gas and oil sales from our Ship Shoal 263 well which began producing in June 2010, and our Rexer #1 well which began producing in October 2010. Also contributing to the increase in sales was an increase in oil and NGL prices received, as well as increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20" pipeline. This increase in sales was partially offset by a decrease in natural gas prices received for the three months ended March 31, 2011.

Average Sales Prices. For the three months ended March 31, 2011, the average price of natural gas was $4.43 per thousand cubic feet ("Mcf") while the average price for oil and condensate was $96.13 per barrel and the average price for NGLs was $1.30 per gallon. For the three months ended March 31, 2010, the average price of natural gas was $5.90 per Mcf while the average price for oil and condensate was $78.48 per barrel and the average price for NGLs was $1.22 per gallon.

Natural Gas, Oil and NGL Production. Our net natural gas production for the three months ended March 31, 2011 was approximately 71.5 Mmcfd, up from approximately 44.9 Mmcfd for the three months ended March 31, 2010. Net oil and condensate production for the comparable periods also increased from approximately 1,100 barrels per day to approximately 2,000 barrels per day, and our NGL production increased from approximately 54,200 gallons per day to approximately

78,200 gallons per day. This increase in natural gas, oil and NGL production was principally attributable to our Ship Shoal 263 well which began producing in June 2010, and our Rexer #1 well which began producing in October 2010. Also contributing to the increase in production were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20” pipeline.

Operating Expenses. Lease operating expenses (“LOE”) for the three months ended March 31, 2011 were approximately $6.4 million, which included approximately $1.5 million in Louisiana state severance taxes. Lease operating expenses for the three months ended March 31, 2010 were approximately $3.5 million, which included approximately $1.0 million in Louisiana state severance taxes. The increase in LOE was attributable to our Ship Shoal 263 well which began producing in June 2010, our Eloise South well which began producing in July 2010 but is currently shut-in, and our Rexer #1 well which began producing in October 2010. Also contributing to the increase in LOE were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20” pipeline.

Exploration Expense. We reported $14,459 of exploration expense for the three months ended March 31, 2011, related to various geological and geophysical activities, seismic data, and delay rentals. For the three months ended March 31, 2010, we reported approximately $22.5 million of exploration expense. Of this amount, approximately $6.1 million related to dry hole costs for Vermilion 155, $16.0 million related to dry hole costs for Matagorda Island 617, and the remaining $0.4 million was attributable 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, 2011 was approximately $15.5 million. For the three months ended March 31, 2010, we recorded approximately $6.8 million of depreciation, depletion and amortization. The increase in depreciation, depletion and amortization was primarily attributable to increased production and increased capitalized costs as a result of our Ship Shoal 263, Eloise South and Rexer #1 discoveries. Also contributing to the increase in depreciation, depletion and amortization were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20” pipeline.

Impairment Expense. For the three months ended March 31, 2011, we recorded impairment expense of approximately $1.7 million related to certain offshore leases. For the three months ended March 31, 2010, we recorded impairment expense of $735,553 related to the relinquishment of South Marsh Island 57, South Marsh Island 59 and South Marsh Island 75.

General and Administrative Expenses. General and administrative expenses for the three months ended March 31, 2011 and the three months ended March 31, 2010 were approximately $5.7 million and $1.2 million, respectively.

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.

Major components of general and administrative expenses for the three months ended March 31, 2010 included approximately $0.3 million in State of Louisiana franchise taxes, $0.5 million in salaries and benefits, $0.1 million in accounting, tax, legal, engineering and other professional fees, $0.2 million in insurance costs, and $0.1 million related to the cost of expensing stock options and stock grant compensation.

Other Income (Expense). We reported other expense of $37,152 for the three months ended March 31, 2011, compared to other income of $539,676 for the three months ended March 31, 2010. This item is a combination of interest income, interest expense, and gain on sale of assets. For the three months ended March 31, 2010, the Company reported a gain on sale of assets of $112,868 related to the sale of its Grand Isle 70 well. Also contributing to the decrease was eliminating the interest rate on the COE Note effective June 1, 2010.

Nine months ended March 31, 2011 Compared to Nine months ended March 31, 2010

Natural Gas, Oil and Natural Gas Liquids (“NGL”) Sales. We reported revenues of approximately $161.7 million for the nine months ended March 31, 2011, compared to revenues of approximately $119.5 million for the nine months ended March 31, 2010. This increase in sales was principally attributable to increased natural gas and oil sales from our Ship Shoal 263 well which began producing in June 2010, our Conterra assets which began producing in December 2009, our Eloise South well which began producing in July 2010 but is currently shut-in, and our Rexer #1 well which began producing in October 2010. Also contributing to the increase in sales was an increase in oil and NGL prices received, as well as increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20” pipeline. This increase in sales was partially offset by a decrease in natural gas prices received for the nine months ended March 31, 2011.

Average Sales Prices. For the nine months ended March 31, 2011, the average price of natural gas was $4.28 per Mcf while the average price for oil and condensate was $85.74 per barrel and the average price for NGLs was $1.13 per gallon. For the nine months ended March 31, 2010, the average price of natural gas was $4.42 per Mcf while the average price for oil and condensate was $73.51 per barrel and the average price for NGLs was $1.04 per gallon.

Natural Gas, Oil and NGL Production. Our net natural gas production for the nine months ended March 31, 2011 was approximately 75.4 Mmcfd, up from approximately 58.4 Mmcfd for the nine months ended March 31, 2010. Net oil and condensate production for the comparable periods also increased from approximately 1,500 barrels per day to approximately 2,000 barrels per day, and our NGL production increased from approximately 68,200 gallons per day to approximately 85,200 gallons per day. This increase in natural gas, oil and NGL production was principally attributable to our Ship Shoal 263 well which began producing in June 2010, our Conterra assets which began producing in December 2009, our Eloise South well which began producing in July 2010 but is currently shut-in, and our Rexer #1 well which began producing in October 2010. Also contributing to the increase in production were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20" pipeline.

Operating Expenses. Lease operating expenses ("LOE") for the nine months ended March 31, 2011 were approximately $17.6 million, which included approximately $3.9 million in Louisiana state severance taxes. Lease operating expenses for the nine months ended March 31, 2010 were approximately $11.1 million, which included approximately $3.7 million in Louisiana state severance taxes. The increase in LOE was attributable to our Conterra production which began producing in December 2009, our Ship Shoal 263 well which began producing in June 2010, our Eloise South well which began producing in July 2010 but is currently shut-in, and our Rexer #1 well which began producing in October 2010. Also contributing to the increase in LOE were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20" pipeline.

Exploration Expense. We reported $10.4 million of exploration expense for the nine months ended March 31, 2011. Of this amount, approximately $9.5 million related to our dry hole at Galveston Area 277L, $0.5 million related to our Conterra joint venture, and the remaining $0.4 million related to various geological and geophysical activities, seismic data, and delay rentals. For the nine months ended March 31, 2010, we reported approximately $22.9 million of exploration expense. Of this amount, approximately $6.1 million related to the dry hole the Company drilled at Vermilion 155, $16.0 million related to the dry hole the Company drilled at Matagorda Island 617, and the remaining $0.8 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, 2011 was approximately $47.0 million. For the nine months ended March 31, 2010, we recorded approximately $25.2 million of depreciation, depletion and amortization. The increase in depreciation, depletion and amortization was primarily attributable to increased production and increased capitalized costs as a result of our Conterra, Ship Shoal 263, Eloise South and Rexer #1 discoveries. Also contributing to the increase in depreciation, depletion and amortization were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20" pipeline.

Impairment Expense. For the nine months ended March 31, 2011, we recorded impairment expense of approximately $1.8 million related to certain offshore leases. For the nine months ended March 31, 2010, we recorded impairment expense of $735,553 related to the relinquishment of South Marsh Island 57, South Marsh Island 59 and South Marsh Island 75.

General and Administrative Expenses. General and administrative expenses for the nine months ended March 31, 2011 and the nine months ended March 31, 2010 were approximately $11.9 million and $4.4 million, respectively.

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.

Major components of general and administrative expenses for the nine months ended March 31, 2010 included approximately $2.4 million in salaries and benefits, $0.6 million in accounting, tax, legal, engineering and other professional fees, $0.1 million in office administration expenses, $0.4 million in insurance costs, and $0.5 million in State of Louisiana franchise taxes, and $0.4 million related to the cost of expensing stock options and stock grant compensation.

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Other Income (Expense). We reported other expense of $121,893 for the nine months ended March 31, 2011, compared to other income of $526,717 for the nine months ended March 31, 2010. This item is a combination of interest income, interest expense, and gain on sale of assets. For the nine months ended March 31, 2010, the Company reported a gain on sale of assets of $112,868 related to the sale of its Grand Isle 70 well. Also contributing to the decrease was eliminating the interest rate on the COE Note effective June 1, 2010.

Production, Prices, Operating Expenses, and Other

	Three Months Ended March 31,		Nine Months Ended March 31,	
	2011	2010	2011	2010
	(Dollar amounts in 000's, except per Mcfe amounts)		(Dollar amounts in 000's, except per Mcfe amounts)	
Production Data:				
Natural gas (million cubic feet)	6,434	4,043	20,670	15,991
Oil and condensate (thousand barrels)	184	102	545	400
Natural gas liquids (thousand gallons)	7,042	4,881	23,358	18,685
Total (million cubic feet equivalent)	8,544	5,352	27,277	21,060
Natural gas (million cubic feet per day)	71.5	44.9	75.4	58.4
Oil and condensate (thousand barrels per day)	2.0	1.1	2.0	1.5
Natural gas liquids (thousand gallons per day)	78.2	54.2	85.2	68.2
Total (million cubic feet equivalent per day)	94.7	59.2	99.6	77.1
Average Sales Price:				
Natural gas (per thousand cubic feet)	$ 4.43	$ 5.90	$ 4.28	$ 4.42
Oil and condensate (per barrel)	$ 96.13	$ 78.48	$ 85.74	$ 73.51
Natural gas liquids (per gallon)	$ 1.30	$ 1.22	$ 1.13	$ 1.04
Total (per thousand cubic feet equivalent)	$ 6.48	$ 7.07	$ 5.93	$ 5.68
Selected data per Mcfe:				
Lease operating expenses	$ 0.75	$ 0.66	$ 0.65	$ 0.53
General and administrative expenses	$ 0.66	$ 0.22	$ 0.44	$ 0.21
Depreciation, depletion and amortization of natural gas and oil properties	$ 1.80	$ 1.24	$ 1.71	$ 1.17

Capital Resources and Liquidity

Cash From Operating Activities. Cash flows from operating activities provided approximately $94.1 million in cash for the nine months ended March 31, 2011 compared to $98.7 million for the same period in 2010. This decrease in cash provided by operating activities was mainly attributable to paying $27.6 million in Federal and State income taxes this period, as compared to $7.1 million for the same period in 2010.

Cash From Investing Activities. Cash flows used in investing activities for the nine months ended March 31, 2011 were approximately $56.8 million, compared to using $41.3 million in investing activities for the nine months ended March 31, 2010. This increase was primarily attributable to increased onshore and offshore capital expenditures for drilling exploration and developmental wells and an investment of $3.5 million in CORE whose stock was distributed to Company shareholders, which was partially offset by repayment of the COE Note.

Cash From Financing Activities. Cash flows used in financing activities for the nine months ended March 31, 2011 were approximately $9.7 million, compared to using approximately $1.4 million for the nine months ended March 31, 2010. During the nine months ended March 31, 2011, the Company repurchased shares of its common stock pursuant to its share repurchase program and incurred debt issuance costs.

Capital Budget. For the remainder of calendar year 2011, the Company has budgeted to invest approximately $69.3 million from cash on hand and operating cash flows, as follows:

- We have budgeted to invest approximately $17.3 million to complete Vermilion 170, build facilities and begin production.
- We have budgeted to invest approximately $6.2 million to recomplete our Eloise South well up hole.
- We have budgeted to invest approximately $0.8 million to workover our Eloise North well.
- We have budgeted to invest approximately $5.0 million to drill and complete our Rexer-Tusa #2 well.
- We have budgeted to invest approximately $20.0 million to drill our Ship Shoal 134 ("Eagle") prospect.
- We have budgeted to invest approximately $20.0 million in our joint venture with Alta Resources, LLC.

Should the Company have exploration success with any of its offshore exploration wells, our capital expenditure budget will be significantly increased.

The Company often reviews acquisitions and prospects presented to us by third parties and 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 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, 2011 and June 30, 2010, based on reserve reports generated by William M. Cobb & Associates, Inc. ("Cobb") and Lonquist & Co. LLC ("Lonquist"). The Company believes that having independent and well respected third-party engineering firms 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 engineers to review these reserve estimates. The qualifications of the technical person at each of these firms primarily responsible for overseeing his firm's preparation of the Company's reserve estimates are set forth below.

William M. Cobb & Associates, Inc.

- 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.

Lonquist & Co. LLC

- Over 21 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.

Each of Cobb and Lonquist 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 engineers quarterly, is confirmed when our third-party reservoir engineers hold 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 engineers 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 firms prepare their independent reserve estimates and final report.

	Proved Reserves as of	
	March 31, 2011	June 30, 2010
Natural Gas (MMcf)	258,671	246,011
Oil, Condensate and Natural Gas Liquids (MBbls)	10,853	11,336
Total proved reserves (Mmcfe)	323,789	314,027

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 engineers 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 most likely will vary from estimates. 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 Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program. Under the program, all shares are purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases will be 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, 2011, the Company purchased the below listed shares under its share repurchase program, resulting in 15,664,666 shares of common stock outstanding and 15,709,666 fully diluted shares:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
July 6 - July 7, 2010	20,000	$ 43.26	1,732,897	$ 23.9 million
November 19, 2010	150,967	$ 58.35	1,883,864	$ 15.1 million
December 23, 2010	1,577	$ 59.91	1,885,441	$ 15.0 million

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 the expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and will be available to fund the Company's offshore Gulf of Mexico 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 a commitment fee of 0.375% will be paid on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of May 1, 2011, the Company was in compliance with all covenants and had no amounts 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 price of 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 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.
- 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. We do not have a written agreement with JEX which contractually obligates JEX to provide us with its services in the 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.

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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.

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 $484 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 drilling contracts at daily rates. Under certain conditions, the turnkey contract can be terminated by the turnkey drilling contractor, which could lead to materially higher risks and costs for the Company.

We rely on third-party operators to operate and maintain some of our production 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 focused in offshore Gulf of Mexico prospects. However, our exploration prospects in the Gulf of Mexico may not lead to significant revenues. Furthermore, we may not be able to drill productive wells at profitable finding and development costs.

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.

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.

The proved reserves assigned to our Dutch and Mary Rose discoveries have ten producing well bores concentrated in two reservoirs on one field, and are producing via two natural gas pipelines, two oil pipelines and two production platforms. Reserve assessments based on only ten well bores in two reservoirs are subject to significantly greater risk of downward revision than multiple well bores from a variety of producing reservoirs.

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

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 engineers. If those reports prove to be inaccurate, our financial reports could have material misstatements. Further, we use the reports of our independent reservoir engineers in our financial planning. If the reports of the outside reservoir engineers 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.
- 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 requires reporting and reductions of 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 counties including 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 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 this year.

In the courts, several decisions have been issued 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.

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.

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, processing plants, and offshore platforms. 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.

The proposed United States federal budget for 2011 and other 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 Obama 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 Obama administration released similar budget proposals for 2011. The proposed budget 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 approximately one year ago, none have become law. It is still, however, the Obama administration's stated intention to enact these provisions.

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 could 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 a directive calling for additional safety and performance standards as well as rigorous monitoring and testing requirements. In addition, various Congressional committees have begun pursuing legislation to regulate drilling activities and increase liability for oil spills.

We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the incident is not yet known. An expansion of safety and performance regulations or an increase in liability for drilling activities may 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.

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, exploration partners and third-party consultants 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 and we do not have any written agreements contractually obligating them to provide us with their services in the future. 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.

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 in September 2008 that is 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. In addition, these provisions, 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.
- 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 May 1, 2011, we had no long-term debt subject to the risk of loss associated with movements in interest rates.

As of March 31, 2011, we had approximately $80.1 million in cash and cash equivalents. Of this amount, approximately $11.7 million was invested in U.S. Treasury money market funds, $11.0 million was invested in overnight U.S. Treasury funds, and the remaining $57.4 million was 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, 2011, 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, 2011, a 10% fluctuation in the prices received for natural gas and oil production would impact our revenues by approximately $16.2 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 Controller, 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, 2011. Based upon that evaluation, the Company's management concluded that, as of March 31, 2011, 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 Controller, 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, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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 a Stockholder Rights Plan (the "Plan") that is 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 is not intended, nor will it operate, to prevent an acquisition of Contango on terms that are favorable and fair to all stockholders.

Under the terms of the Plan, each right (a "Right") will entitle the holder to buy 1/100 of a share of Series F Junior Preferred Stock of Contango (the "Preferred Stock") at an exercise price of $200 per share. The Rights will be exercisable and will trade separately from the shares of common stock only if a person or group acquires beneficial ownership of 20% or more of Contango's common stock or commences a tender or exchange offer that would result in such a person or group owning 20% or more of the common stock (the "Triggering Event").

Under the terms of the Plan, Rights have been distributed as a dividend at the rate of one Right for each share of common stock held as of the close of business on October 1, 2008. Stockholders will not actually receive certificates for the Rights at this time, but the Rights will become part of each outstanding share of common stock. An additional Right will be issued along with each share of common stock that is issued or sold by Contango after October 1, 2008. The Rights may only be exercised during a three-year period and are scheduled to expire on September 30, 2011. Upon a Triggering Event, Contango stockholders will receive certificates for the Rights.

If any person actually acquires 20% or more of shares of common stock — other than through a tender or exchange offer for all shares of common stock that provides a fair price and other acceptable terms for such shares, as determined by the board of directors of Contango — or if a 20%-or-more stockholder engages in certain "self-dealing" transactions or engages in a merger or other business combination in which Contango survives and its shares of common stock remain outstanding, the other Contango stockholders will be able to exercise the Rights and buy shares of common stock of Contango having approximately twice the value of the exercise price of the Rights. Additionally, if Contango is involved in certain other mergers where its shares are exchanged or certain major sales of its assets occur, Contango stockholders will be able to purchase a certain number of the other party's common stock in an amount equal to approximately twice the value of the exercise price of the Rights.

Contango will be entitled to redeem the Rights at $0.01 per Right at any time until the earlier of (i) the tenth day following public announcement that a person has acquired a 20% ownership position in shares of common stock of Contango or (ii) the final expiration date of the Rights. Contango in its discretion may extend the period during which it may redeem the Rights.

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)
23.1	Consent of William M. Cobb & Associates, Inc. †
23.2	Consent of Lonquist & Co. LLC. †
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. †

† 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.

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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 10, 2011

By: /s/ KENNETH R. PEAK
Kenneth R. Peak
Chairman and Chief Executive Officer
(Principal Executive Officer)

Date: May 10, 2011

By: /s/ SERGIO CASTRO
Sergio Castro
Chief Financial Officer
(Principal Financial Officer)

Date: May 10, 2011

By: /s/ YAROSLAVA MAKALSKAYA
Yaroslava Makalskaya
Vice President and Controller
(Principal Accounting Officer)

Exhibit 23.1

WILLIAM M. COBB & ASSOCIATES, INC.

May 10, 2011

Contango Oil & Gas Company
3700 Buffalo Speedway, Suite 960
Houston, Texas 77098

Re: Contango Oil & Gas Company, Quarterly Report on Form 10-Q

Gentlemen:

The firm of William M. Cobb & Associates, Inc. consents to the use of its name and to the use of its projections for Contango Oil & Gas Company's Proved Reserves and Future Net Revenue in Contango's Report on Form 10-Q for the quarter ended March 31, 2011.

William M. Cobb & Associates, Inc. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Yours very truly,

WILLIAM M. COBB & ASSOCIATES, INC.

/s/ F.J. MAREK

F.J. Marek, P.E.
Senior Vice President

Exhibit 23.2

LONQUIST & CO. LLC

May 10, 2011

Contango Oil & Gas Company
3700 Buffalo Speedway, Suite 960
Houston, Texas 77098

Re: Contango Oil & Gas Company, Quarterly Report on Form 10-Q

Gentlemen:

The firm of Lonquist & Co. LLC consents to the use of its name and to the use of its projections for Contango Oil & Gas Company's Proved Reserves and Future Net Revenue in Contango's Report on Form 10-Q for the quarter ended March 31, 2011.

Lonquist & Co. LLC has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Yours very truly,

LONQUIST & CO. LLC

/s/ Richard R. Lonquist
RICHARD R. LONQUIST, P.E.

Exhibit 31.1

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Kenneth R. Peak, Chairman and Chief Executive Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: May 10, 2011

/s/ KENNETH R. PEAK

Kenneth R. Peak
Chairman and Chief Executive Officer

Exhibit 31.2

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Sergio Castro, Chief Financial Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: May 10, 2011

/s/ SERGIO CASTRO

Sergio Castro
Chief Financial Officer

Exhibit 32.1

CONTANGO OIL & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Contango Oil & Gas Company (the "Company") on Form 10-Q for the period ending March 31, 2011 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Kenneth R. Peak, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Dated: May 10, 2011

/s/ KENNETH R. PEAK
Kenneth R. Peak
Chairman and Chief Executive Officer

Exhibit 32.2

CONTANGO OIL & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Contango Oil & Gas Company (the "Company") on Form 10-Q for the period ending March 31, 2011 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Sergio Castro, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Dated: May 10, 2011

/s/ SERGIO CASTRO
Sergio Castro
Chief Financial Officer