CONTANGO OIL & GAS CO
Form 10-Q
February 11, 2013

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

FORM 10-Q

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

For the quarterly period ended December 31, 2012

OR

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

For the transition period from to

Commission file number 001-16317

CONTANGO OIL & GAS COMPANY
(Exact name of registrant as specified in its charter)

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

3700 BUFFALO SPEEDWAY, SUITE 960
HOUSTON, TEXAS 77098
(Address of principal executive offices)
(713) 960-1901
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý 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 ý 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 ý	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 ý

The total number of shares of common stock, par value $0.04 per share, outstanding as of February 1, 2013 was 15,194,952.

1

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY REPORT ON FORM 10-Q
FOR THE SIX MONTHS ENDED DECEMBER 31, 2012
TABLE OF CONTENTS

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)

	December 31, 2012	June 30, 2012
	(thousands)	
CURRENT ASSETS:		
Cash and cash equivalents	$79,487	$129,983
Accounts receivable:		
Trade receivables	28,090	29,688
Joint interest billings	3,934	4,768
Income taxes	16,177	4,510
Other	649	242
Prepaid expenses	2,479	5,762
Inventory	2,757	260
Total current assets	133,573	175,213
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	554,967	561,713
Unproved properties	22,662	12,485
Furniture and equipment	227	213
Accumulated depreciation, depletion and amortization	(197,874)	(178,081)
Total property, plant and equipment, net	379,982	396,330
OTHER ASSETS:		
Investments in affiliates	47,327	52,827
Other	224	284
TOTAL ASSETS	$561,106	$624,654
CURRENT LIABILITIES:		
Accounts payable	$4,335	$3,084
Royalties and revenue payable	22,281	22,098
Accrued liabilities	4,848	6,796
Accrued exploration and development	1,208	2,334
Total current liabilities	32,672	34,312
DEFERRED TAX LIABILITY	115,858	118,010
ASSET RETIREMENT OBLIGATIONS	8,647	7,993
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50,000,000 shares authorized; 20,135,107 shares issued and 15,194,952 outstanding at December 31, 2012; 20,135,107 shares issued and 15,292,448 outstanding at June 30, 2012	805	805
Additional paid-in capital	79,024	79,024
Treasury shares at cost (4,940,155 shares at December 31, 2012 and 4,842,659 shares at June 30, 2012)	(117,162)	(112,207)
Retained earnings	441,262	496,717
Total shareholders' equity	403,929	464,339
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$561,106	$624,654

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011
	(thousands, except per share amounts)			
REVENUES:				
Natural gas, oil and liquids sales	$34,940	$53,907	$64,705	$98,109
Total revenues	34,940	53,907	64,705	98,109
EXPENSES:				
Operating expenses	4,973	7,010	11,435	12,899
Exploration expenses	6,629	33	51,614	56
Depreciation, depletion and amortization	10,770	13,536	20,336	24,493
Impairment of natural gas and oil properties	5,668	—	14,078	—
General and administrative expenses	2,818	2,304	5,398	4,552
Total expenses	30,858	22,883	102,861	42,000
Gain from investments in affiliates, net of taxes	344	—	508	—
Other income/(expense)	(173)	(51)	(185)	(128)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	4,253	30,973	(37,833)	55,981
Income tax benefit (provision)	(1,649)	(11,383)	12,888	(20,806)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	2,604	19,590	(24,945)	35,175
DISCONTINUED OPERATIONS (NOTE 8)				
Discontinued operations, net of income taxes	—	(114)	—	(795)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$2,604	$19,476	$(24,945)	$34,380
NET INCOME (LOSS) PER SHARE:				
Basic				
Continuing operations	$0.17	$1.28	$(1.64)	$2.27
Discontinued operations	—	(0.01)	—	(0.05)
Total	$0.17	$1.27	$(1.64)	$2.22
Diluted				
Continuing operations	$0.17	$1.28	$(1.64)	$2.27
Discontinued operations	—	(0.01)	—	(0.05)
Total	$0.17	$1.27	$(1.64)	$2.22
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	15,198	15,362	15,246	15,501
Diluted	15,198	15,365	15,246	15,504

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended December 31, 2012		2011	
	(thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss) from continuing operations	$(24,945	)	$35,175	
Loss from discontinued operations, net of income taxes	—		(795	)
Net income (loss)	(24,945	)	34,380	
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	20,336		24,493	
Impairment of natural gas and oil properties	14,078		1,031	
Exploration expenses	51,379		—	
Deferred income taxes	(2,152	)	701	
Gain from investment in affiliates	(782	)	—	
Loss on sale of assets	—		169	
Stock-based compensation	—		158	
Changes in operating assets and liabilities:				
Decrease (increase) in accounts receivable and other	1,597		(3,956	)
Decrease in prepaids and other receivables	1,645		2,259	
Increase in inventory	(2,497	)	—	
Increase (decrease) in accounts payable and advances from joint owners	2,267		(14,570	)
Decrease in other accrued liabilities	(1,948	)	(4,484	)
Increase in income taxes receivable, net	(11,668	)	(7,908	)
Other	(364	)	378	
Net cash provided by operating activities	$46,946		$32,651	
CASH FLOWS FROM INVESTING ACTIVITIES:				
Natural gas and oil exploration and development expenditures	(68,623	)	(13,027	)
Advances under note receivable	—		(400	)
Investment in affiliates	(1,500	)	(141	)
Return of investments in affiliates	8,146		—	
Net cash used in investing activities	$(61,977	)	$(13,568	)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Dividends Paid	(30,510	)	—	
Purchase of common stock	(4,955	)	(17,000	)
Net cash used in financing activities	$(35,465	)	$(17,000	)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(50,496	)	2,083	
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	129,983		150,007	
CASH AND CASH EQUIVALENTS, END OF PERIOD	$79,487		$152,090	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid for taxes, net of cash received	$1,205		$27,585	
Cash paid for interest	$25		$75	

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(Unaudited)

	Common Stock		Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
	Shares	Amount				
	(thousands)					
Balance at June 30, 2012	15,292	$805	$79,024	$(112,207)	$496,717	$464,339
Net loss	—	—	—	—	(27,549)	(27,549)
Balance at September 30, 2012	15,292	$805	$79,024	$(112,207)	$469,168	$436,790
Treasury shares at cost	(97)	$—	$—	$(4,955)	$—	$(4,955)
Dividends	—	$—	$—	$—	$(30,510)	$(30,510)
Net income	—	$—	$—	$—	$2,604	$2,604
Balance at December 31, 2012	15,195	$805	$79,024	$(117,162)	$441,262	$403,929

The accompanying notes are an integral part of this consolidated financial statement

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

1. Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information, pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”), including instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements. In the opinion of management, all adjustments considered necessary for a fair statement of the unaudited consolidated financial statements have been included. All such adjustments are of a normal recurring nature. The consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in Contango Oil & Gas Company’s ("Contango" or the "Company") Form 10-K for the fiscal year ended June 30, 2012. The consolidated results of operations for the three and six months ended December 31, 2012 are not necessarily indicative of the results that may be expected for the fiscal year ending June 30, 2013.

2. Business

We are a Houston-based, independent natural gas and oil company. Our core business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet, using cash generated from our existing property base. We have no debt.

In July 2012, we unsuccessfully drilled two exploration prospects at Ship Shoal 134 ("Eagle") and South Timbalier 75 ("Fang"), and found no commercial hydrocarbons. For the three and six months ended December 31, 2012, we recorded exploration expenses of approximately $6.3 million and $50.0 million, respectively, including leasehold costs, related to these two wells.

As of December 31, 2012, we had invested approximately $13.1 million with Alta Energy Canada Partnership, G.P. ("Alta Energy"), whose primary area of focus is the liquids-rich Kaybob Duvernay in Alberta, Canada. We had also invested approximately $33.8 million with Exaro Energy III LLC ("Exaro") in the Jonah field in Wyoming, which is primarily focused on the development of proved reserves. In addition, as of December 31, 2012, the Company had invested approximately $9.0 million in leasehold costs in the Tuscaloosa Marine Shale ("TMS") for approximately 24,000 acres, plus an additional $4.3 million to acquire acreage and a 25% non-operated working interest to drill a horizontal well with Goodrich Petroleum Company ("Goodrich") in the TMS.

On November 29, 2012, the Board of the Company declared a special dividend of $2.00 per share of common stock which was paid on December 17, 2012 to each holder of record of the Company's common stock as of the close of business on December 10, 2012.

3. Summary of Significant Accounting Policies

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

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

Impairment of Long-Lived Assets. 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. For the three months ended December 31, 2012, we recorded an impairment expense of approximately $5.7 million related to our Ship Shoal 263 well. For the six months ended December 31, 2012, we recorded an impairment expense of approximately $14.1 million related to proved properties. Of this amount, approximately $12.0 million related to our Ship Shoal 263 well and $2.1 million related to the Eugene Island 24 platform and other properties. Despite the writedowns on Ship Shoal 263, this well reached payout during fiscal year 2012. No impairment of proved properties was recognized in continuing operations for the three or six months ended December 31, 2011.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. For the three and six months ended December 31, 2012, the Company recognized impairment expense of approximately $0.2 million and $1.4 million, respectively, related to an unsuccessful exploration program in Jim Hogg County, Texas. Additionally, for the six months ended December 31, 2012, the Company recognized impairment expenses of approximately $6.6 million related to leasehold costs at our dry holes at Ship Shoal 134 and South Timbalier 75. All these costs are included in total exploration expense, along with drilling, plugging and abandoning costs for Eagle and Fang. No impairment of unproved properties was recognized during the three or six months ended December 31, 2011.

Cash Equivalents. Cash equivalents are considered to be highly liquid investment grade investments having an original maturity of 90 days or less. As of December 31, 2012, the Company had approximately $79.5 million in cash and cash equivalents, all of which was held in non-interest bearing accounts.

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

Other Investments. The Company's 2.0% ownership interest in Alta Energy is accounted for using the cost method. The Company also has a 37% ownership interest in Exaro. The Company has two seats on the board of directors of Exaro, and has significant influence, but not control, over Exaro. As a result, the Company's 37% ownership in Exaro is accounted for using the equity method.

The Company originally had a 45% ownership interest in Exaro upon its formation in April 2012. In August 2012, one of the other investors in Exaro exercised its right to assume $15 million of the Company's commitment by making a cash payment to the Company of $7.5 million and agreeing to assume $7.5 million of future commitment in Exaro. This lowered the Company's ownership interest to 37%. As of December 31, 2012, the Company had invested approximately $33.8 million in Exaro.

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

Reclassifications. Certain reclassifications have been made to the amounts included in the consolidated financial statements as of June 30, 2012 and for the three and six months ended December 31, 2011, in order to conform to the presentation as of and for the three and six months ended December 31, 2012. These reclassifications were not material.

4. 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 the Company's 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.

5. 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 three and six months ended December 31, 2012 were ConocoPhillips Company, Shell Trading US Company, Exxon Mobil Oil Corporation, Enterprise Products Operating LLC, Crosstex Energy Services, JP Morgan Ventures Energy Corporation and Trans Louisiana Gas Pipeline, Inc. 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.

6. Net Income (Loss) per Common Share

A reconciliation of the components of basic and diluted net income (loss) per share of common stock is presented below:

	Three Months Ended December 31, 2012			Three Months Ended December 31, 2011		
	Income	Shares	Per Share	Income (loss)	Shares	Per Share
	(thousands, except per share amounts)					
Net income from continuing operations	$2,604	15,198	$0.17	$19,590	15,362	$1.28
Discontinued operations, net of income tax	—	15,198	—	(114)	15,362	(0.01)
Basic Earnings per Share:						
Net income attributable to common stock	$2,604	15,198	$0.17	$19,476	15,362	$1.27
Effect of potential dilutive securities:						
Stock options, net of shares assumed purchased	—	—		—	3	
Net income from continuing operations	$2,604	15,198	$0.17	$19,590	15,365	$1.28
Discontinued operations, net of income tax	—	15,198	—	(114)	15,365	(0.01)
Diluted Earnings per Share:						
Net income attributable to common stock	$2,604	15,198	$0.17	$19,476	15,365	$1.27

	Six Months Ended December 31, 2012			Six Months Ended December 31, 2011		
	Loss	Shares	Per Share	Income (loss)	Shares	Per Share
	(thousands, except per share amounts)					
Net income (loss) from continuing operations	$(24,945)	15,246	$(1.64)	$35,175	15,501	$2.27
Discontinued operations, net of income tax	—	15,246	—	(795)	15,501	(0.05)
Basic Earnings per Share:						
Net income (loss) attributable to common stock	$(24,945)	15,246	$(1.64)	$34,380	15,501	$2.22
Effect of potential dilutive securities:						
Stock options, net of shares assumed purchased	—	—		—	3	
Income (loss) from continuing operations	$(24,945)	15,246	$(1.64)	$35,175	15,504	$2.27
Discontinued operations, net of income tax	—	15,246	—	(795)	15,504	(0.05)
Diluted Earnings per Share:						
Net income (loss) attributable to common stock	$(24,945)	15,246	$(1.64)	$34,380	15,504	$2.22

7. Credit Facility

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

8. Discontinued Operations

In May 2011, the Company sold its 100% working interest (72.5% net revenue interest) in Rexer #1 and its 75% working interest (54.4% net revenue interest) in Rexer-Tusa #2 to Patara Oil & Gas LLC ("Patara"). B.A. Berilgen, a member of the Company's board of directors, was the Chief Executive Officer of Patara at the time of the sale. In October 2011, the Company sold its remaining 25% working interest (18.4% net revenue interest) in Rexer-Tusa #2 to Patara. The sale was effective October 1, 2011. The Company has accounted for the sale of Rexer #1 and Rexer-Tusa #2 as discontinued operations as of December 31, 2011 and reclassified the results of operations for these two wells to discontinued operations for all periods presented as follows:

	Three Months Ended December 31, 2011	Six Months Ended December 31, 2011
Results of Operations:		
Revenues	$6	$6
Operating expenses	(12)	(22)
Exploration expenses	—	(7)
Impairment of natural gas and oil properties	—	(1,031)
Loss on sale of discontinued operations	$(169)	$(169)
Loss before income taxes	(175)	(1,223)
Income tax benefit	61	428
Loss from discontinued operations, net of income taxes	$(114)	$(795)

9. Income Taxes

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

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011
Current tax provision (benefit):				
Federal	$(3,862)	$9,893	$(11,647)	$18,139
State	616	894	1,185	1,801
Total	$(3,246)	$10,787	$(10,462)	$19,940
Deferred tax provision (benefit):				
Federal	$5,025	$789	$(2,172)	$1,075
State	(130)	(193)	(254)	(209)
Total	$4,895	$596	$(2,426)	$866
Total tax provision (benefit):				
Federal	$1,163	$10,682	$(13,819)	$19,214
State	486	701	931	1,592
Total	$1,649	$11,383	$(12,888)	$20,806

10. Related Party Transactions

Juneau Exploration L.P. In April 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of Juneau Exploration, L.P. ("JEX"), had joined the Company's board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango's staff on operational matters including drilling, completions and production. Pursuant to the Advisory Agreement, JEX was paid an annual fee of $2.0 million.

10

Effective January 1, 2013, the Advisory Agreement was terminated, and the Company and JEX entered into a First Right of Refusal Agreement (the "First Right Agreement"). Under the First Right Agreement, JEX granted a first right of refusal to Contango to purchase any exploration prospects generated and recommended by JEX. Prospects will be presented along with terms and conditions for purchasing each prospect and Contango shall have the first right of refusal to purchase the prospect from JEX for a period of 10 days, subject to mutually acceptable terms. Pursuant to the First Right Agreement, JEX will be paid an annual fee of $0.5 million, which approximates the costs incurred by JEX for their continued support to the Company in the areas of operations, engineering, and land functions.

Effective January 1, 2013, Contaro Company, a wholly-owned subsidiary of the Company, entered into an advisory agreement with JEX (the "Contaro Advisory Agreement"). Under the Contaro Advisory Agreement, JEX will provide advisory services to Contaro in connection with Contaro's investment in Exaro, and Mr. Juneau will serve on the board of managers of Exaro and perform such duties as described in the limited liability company operating agreement of Exaro. Pursuant to the Contaro Advisory Agreement, JEX will be paid a monthly fee of $10,000 and shall be entitled to receive a one percent (1%) fee of the cash profit earned by Contaro. Cash profit is defined as the amount of cash received by Contango as a result of its investment in Contaro, less the cash invested by the Company as a result of its investment in Contaro.

In August 2012, the Company's Chairman and Chief Executive Officer, Mr. Kenneth R. Peak, took a leave of absence, and the Board of Directors of the Company appointed Mr. Juneau as President and Acting Chief Executive Officer of the Company. In December 2012, Mr. Joseph J. Romano was elected President and Chief Executive Officer of the Company. Mr. Romano is the President and Chief Executive Officer of Olympic Energy Partners LLC ("Olympic"). Mr. Peak remains the Company's Chairman.

JEX and Olympic have historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest ("WI"), net revenue interest ("NRI"), and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX, excluding Mr. Juneau, except where otherwise noted. Olympic last participated with the Company in the drilling of wells in March 2010, and does not anticipate participating in any future wells. Olympic's ownership in Company-operated wells is limited to our Dutch and Mary Rose wells.

Republic Exploration LLC. In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

As of December 31, 2012, Contango, Olympic, JEX, REX and JEX employees owned the following interests in the Company's offshore wells.

	Contango		Olympic		JEX		REX		JEX Employees
	WI	NRI	WI	NRI	WI	NRI	WI	NRI	ORRI
Dutch #1 - #5	47.05%	38.12%	3.02%	2.42%	1.61%	1.29%	—%	—%	2.02%
Mary Rose #1	53.21%	40.45%	3.61%	2.7%	2.01%	1.51%	—%	—%	2.79%
Mary Rose #2 - #3	53.21%	38.67%	3.61%	2.58%	2.01%	1.44%	—%	—%	2.79%
Mary Rose #4	34.58%	25.49%	2.34%	1.7%	1.31%	0.95%	—%	—%	1.82%
Mary Rose #5	37.80%	27.88%	2.56%	1.87%	1.43%	1.04%	—%	—%	1.54%
Ship Shoal 263	100.00%	80.00%	—%	—%	—%	—%	—%	—%	3.33%
Vermilion 170	83.20%	64.83%	—%	—%	4.30%	3.35%	12.50%	9.74%	3.33%

Below is a summary of payments received from (paid to) Olympic, JEX and REX in the ordinary course of business in our capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types of payments with other well owners (in thousands):

11

	Three months ended December 31,					
	2012			2011		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$(1,510)	$(1,089)	$(741)	$(2,261)	$(1,429)	$(418)
Joint interest billing receipts	235	199	230	251	257	776

	Six months ended December 31,					
	2012			2011		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$(3,050)	$(2,222)	$(1,590)	$(4,615)	$(2,712)	$(448)
Joint interest billing receipts	529	419	321	680	503	1,858

Below is a summary of payments received from (paid to) Olympic, JEX and REX as a result of specific transactions between the Company, Olympic, JEX and REX. While these payments are in the ordinary course of business, the Company did not have similar transactions with other well owners (in thousands):

	Three months ended December 31,					
	2012			2011		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$—	$(255)	$—	$—	$(1)	$—
Payments under April 1, 2012 Advisory Agreement	—	(333)	—	—	—	—
REX distribution to members	—	—	323	—	—	—

	Six months ended December 31,					
	2012			2011		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$—	$(401)	$—	$(10)	$(6)	$(10)
Prospect fees	—	—	—	—	(250)	—
Payments under April 1, 2012 Advisory Agreement	—	(1,000)	—	—	—	—
REX distribution to members	—	—	646	—	—	—

As of December 31, 2012 and June 30, 2012, the Company's consolidated balance sheets included the following balances (in thousands):

	December 31, 2012			June 30, 2012		
	Olympic	JEX	REX	Olympic	JEX	REX
Accounts receivable:						
Trade receivables	$2	$1	$1	$10	$20	$18
Joint interest billings	79	85	78	192	158	92
Accounts payable:						
Royalties and revenue payable	$(1,133)	$(842)	$(642)	$(1,198)	$(813)	$(682)
Joint interest billings	—	(101)	—	—	—	—

In addition to the above, the Company paid Mr. Brad Juneau $28,000 and $56,000 during the three and six months ended December 31, 2012 for his services as a director of the Company.

11. Share Repurchase Programs
$100 Million Share Repurchase Program
In September 2008, the Board approved a $100 million share repurchase program. All shares were purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases were made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock became authorized but unissued shares, and may be issued in the future for general corporate and other purposes.
During the three months ended December 31, 2011, the Company purchased 28,137 shares at an average price of $54.09 per share, for a total of approximately $1.5 million. During the six months ended December 31, 2011, the Company purchased 271,837 shares at an average price of $55.38 per share, for a total of approximately $15.1 million. The $100 million share repurchase program concluded in October 2011.
$50 Million Share Repurchase Program
In September 2011, the Board approved a $50 million share repurchase program, effective upon completion of purchases under the Company’s $100 million share repurchase program. The purchases made under the $50 million share repurchase program will be subject to the same terms and conditions as purchases made under the $100 million share repurchase program. During the three and six months ended December 31, 2012, the Company purchased 97,496 shares at an average price of $50.82 per share, for a total of approximately $5.0 million. During the three and six months ended December 31, 2011, the Company purchased 35,663 shares at an average price of $54.58 per share, for a total of approximately $1.9 million.
As of December 31, 2012, under both share repurchase programs combined, the Company had purchased approximately 2.4 million shares of its common stock at an average cost per share of $46.84, and 45,000 stock options, for a total of approximately $110.8 million, bringing its total share count as of December 31, 2012 to 15,194,952 shares of common stock outstanding.
12. Subsequent Events

As of December 31, 2012, the Company had invested approximately $13.1 million in Alta Energy to drill in the Kaybob Duvernay shale in Alberta, Canada. In January 2013, we invested an additional $1.0 million, bringing the Company's total investment in Alta Energy to approximately $14.1 million.

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, 2012, previously filed with the SEC.

Executive Overview

Contango Oil & Gas Company (“Contango” or the “Company”) is a Houston-based, independent natural gas and oil company. Our core business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet, using cash generated from our existing property base. We have no debt.

During the six months ended December 30, 2012, we unsuccessfully drilled two exploration prospects for a total cost of approximately $50.0 million, which includes leasehold costs of $6.6 million, and found no commercial hydrocarbons. As of February 1, 2013, our offshore production was approximately 60.3 million cubic feet equivalent per day ("Mmcfed").

Onshore, we have invested approximately $14.1 million with Alta Energy Canada Partnership, G.P. ("Alta Energy") for a 2% ownership interest in Alta Energy, whose primary area of focus is the liquids-rich Kaybob Duvernay in Alberta, Canada. We have also invested approximately $33.8 million with Exaro Energy III LLC ("Exaro") for a 37% ownership interest in Exaro, whose primary area of focus is the Jonah field in Wyoming, which is primarily development of proved reserves. In addition, the Company has invested $4.3 million as a 25% working interest owner in the Crosby 12H-1, a well operated by Goodrich Petroleum Company LLC ("Goodrich") in the Tuscaloosa Marine Shale (“TMS”), an oil focused shale play in central Louisiana and Mississippi. As of February 6, 2013 the Crosby 12H-1 was producing at an 8/8ths rate of approximately 1,250 barrels of oil equivalent ("BOE") per day. Lastly, we have invested approximately $9.0 million in leasehold costs for approximately 24,000 acres in the TMS. The data we obtain from the Goodrich well will help us evaluate our TMS acreage and develop a plan for drilling and operating future wells.

Exploration Program Summary

On July 3, 2012, we spud our Ship Shoal 134 prospect ("Eagle") with the Hercules 205 rig. On October 19, 2012, we announced that we had reached total depth on Eagle and no commercial hydrocarbons were found. The Company has plugged and abandoned this well. For the six months ended December 31, 2012, we incurred approximately $28.9 million to drill, plug and abandon this well, including approximately $6.3 million in leasehold costs.

On July 10, 2012 we spud our South Timbalier 75 prospect ("Fang") with the Spartan 303 rig. On October 30, 2012, we announced that we had reached total depth on Fang and no commercial hydrocarbons were found. The Company has plugged and abandoned this well. For the six months ended December 31, 2012, we incurred approximately $21.1 million to drill, plug and abandon this well, including approximately $0.3 million in leasehold costs. This prospect was a farm-in and the lease was never earned as a result of the dry hole.

Prior to drilling Eagle and Fang, our previous two prospects were discoveries, which were spud in October 2009 and February 2011. Due to the delay in rig availability and drilling permits, it has taken us over a year to spud new wells. On June 20, 2012, the Company was the apparent high bidder on six lease blocks at the Central Gulf of Mexico Lease Sale 216/222. The Company bid an aggregate amount of approximately $11 million on these blocks. We have submitted an exploration permit for the first of these blocks, Ship Shoal 255, and have budgeted to spud this well in mid-2013. Additionally, we will continue to evaluate new onshore and offshore prospects and will be prepared to place bids at the next Gulf of Mexico lease sale in March 2013. Until we start drilling in mid to late-2013, our plan is to accumulate cash from our producing wells to provide future funding for new prospects and opportunities. As of

February 1, 2013, we had approximately $81.9 million of cash, $40.0 million of unused borrowing capacity, and no debt.

Our Strategy

Our exploration strategy is predicated upon the belief that the only competitive advantage in the commodity-based natural gas and oil business is to be among the lowest cost producers. As a result, our business strategy includes the following elements:

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

Using our limited capital availability to increase our reward/risk potential on selective prospects. We have concentrated our risk investment capital in exploration of i) offshore Gulf of Mexico prospects and ii) conventional and unconventional onshore plays. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success.

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.

Exploration Alliance with JEX

JEX is a private company formed for the purpose of generating offshore and onshore domestic natural gas and oil prospects for the Company, either directly, 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 prospects, JEX occasionally evaluates exploration prospects generated by third-party independent companies. Once we agree to a prospect from JEX, REX or a third-party, we enter into a participation agreement and joint operating agreement specifying each participant’s working interest, net revenue interest, and description of when such interests are earned, as well as allocating an overriding royalty interest of up to 3.33% to benefit employees of JEX.

On April 10, 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of JEX, had joined the Company’s board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango’s staff on operational matters including drilling, completions and production. Pursuant to the Advisory Agreement, JEX was paid an annual fee of $2.0 million.

Effective January 1, 2013, the Advisory Agreement was terminated, and the Company and JEX entered into a First Right of Refusal Agreement (the "First Right Agreement"). Under the First Right Agreement, JEX granted a first right of refusal to Contango to purchase any exploration prospects generated and recommended by JEX. Prospects will be presented along with terms and conditions for purchasing each prospect and Contango shall have the first right of refusal to purchase the prospect from JEX for a period of 10 days, subject to mutually acceptable terms. Pursuant to the First Right Agreement, JEX will be paid an annual fee of $0.5 million which approximates the costs incurred by JEX for their continued support to the Company in the areas of operations, engineering, and land functions. JEX and its employees will continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights.

Effective January 1, 2013, Contaro Company, a wholly-owned subsidiary of the Company, entered into an advisory agreement with JEX (the "Contaro Advisory Agreement"). Under the Contaro Advisory Agreement, JEX will provide advisory services to Contaro in connection with Contaro's investment in Exaro, and Mr. Juneau will serve on the Board of Managers of Exaro and perform such duties as described in the limited liability company operating agreement of Exaro. Pursuant to the Contaro Advisory Agreement, JEX will be paid a monthly fee of $10,000 and shall be entitled to receive a one percent (1%) fee of the cash profit earned by Contaro. Cash profit is defined as the amount of cash received by Contango as a result of its investment in Contaro, less the cash invested by the Company as a result of its investment in Contaro.

Offshore Gulf of Mexico Exploration Joint Ventures

Contango, through its wholly-owned subsidiary Contango Operators, Inc. ("COI"), and its partially-owned subsidiary REX, conducts exploration activities in the Gulf of Mexico. As of February 1, 2013, Contango, through COI and REX, had an interest in 20 offshore leases. See “Offshore Properties” for additional information on our offshore properties.

Contango Operators, Inc.
COI acquires leasehold acreage, drills and operates our wells in the Gulf of Mexico. Additionally, COI may acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, under farm-out agreements, or similar agreements, with REX, JEX and/or third parties.
As of February 1, 2013, the Company's offshore production was approximately 60.3 Mmcfed, net to Contango, which consists of seven federal and five state of Louisiana wells in the shallow waters of the Gulf of Mexico. These 12 operated wells produce through the following three platforms:
Eugene Island 11 Platform

Our Company-owned and operated production platform at Eugene Island 11 was designed with a capacity of 500 Mmcfd and 6,000 bopd. In September 2010 the Company installed a companion platform and two pipelines adjacent to the Eugene Island 11 platform to be able to access alternate markets. These platforms service production from the Company's five Dutch wells in federal waters and five Mary Rose wells in state of Louisiana waters. From these platforms, a portion of our gas and condensate flows to our Eugene Island 63 auxiliary platform via our 20" pipeline, which has been designed with a capacity of 330 Mmcfd and 6,000 bopd, and then from there to third-party owned and operated on-shore processing facilities near Patterson, Louisiana, via an ANR pipeline.

The remaining gas flows to the American Midstream pipeline via our 8" pipeline, which has been designed with a capacity of 80 Mmcfd, and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. The remaining condensate can flow via an ExxonMobil pipeline to on-shore markets and multiple refineries. As of February 1, 2013, we were producing approximately 59.1 Mmcfed, net to Contango, from this platform.

Based on production and decline rates, the Company has determined the need to place its Dutch and Mary Rose wells on compression in late-2013 or early-2014. The Company is in the process of designing and building a large turbine type compressor for the platform at an estimated cost of $6.8 million, net to Contango. This compressor will be of sufficient capacity to service all ten of the Company's Dutch and Mary Rose wells. As of December 31, 2012, the Company had incurred approximately $4.1 million to design and build the compressor.

Ship Shoal 263 Platform

Our Company-owned and operated platform at Ship Shoal 263 was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services natural gas and condensate production from our Nautilus well, which both flow via the Transcontinental Gas Pipeline to onshore processing plants. As of February 1, 2013, we were producing approximately 1.2 Mmcfed, net to Contango, from this platform.

We believe that our Nautilus well may be fully depleted within the next year. Despite this, the well reached payout during fiscal year 2012. We will continue producing this well as long as it is economical. Should we have a discovery at our Ship Shoal 255 prospect, we intend to take the new production to this platform.
Vermilion 170 Platform
Our Company-owned and operated platform at Vermilion 170 was designed with a capacity of 60 Mmcfd and 2,000 bopd. This platform services natural gas and condensate production from our Swimmy well which began producing in September 2011. The production flows via the Sea Robin Pipeline to onshore processing plants. Based on current production and decline rates, the Company has determined the need to place its Vermilion 170 well on compression, at a cost of $1.4 million, net to Contango. As of December 31, 2012, the Company had incurred approximately $1.4 million to install the compressor, which we expect to begin operating in mid-2013.

In late January 2013 we encountered a downhole problem at Swimmy and shut-in the well. We have scheduled a workover to replace downhole tubing and expect the well to resume production by mid-March 2013.

Republic Exploration LLC
In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects for the Company and has historically participated with the Company in the drilling

16

and development of certain prospects through participation agreements and joint operating agreements, which specify each participant's working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

Offshore Properties

Producing Properties. The following table sets forth the interests owned by Contango through its affiliated entities in the Gulf of Mexico which were capable of producing natural gas or oil as of February 1, 2013:

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

Leases. The following table sets forth the working interests owned by Contango and affiliated entities in non-developed leases in the Gulf of Mexico as of February 1, 2013.

Area/Block	WI		Lease Date	Expiration Date
East Breaks 369 (Dry Hole)	(1	)	Dec-03	Dec-13
South Timbalier 97 (via REX)	32.30	%	Jun-09	Jun-14
Ship Shoal 121	100.00	%	Jul-10	Jul-15
Ship Shoal 122	100.00	%	Jul-10	Jul-15
Brazos Area 543	100.00	%	Mar-12	Mar-17
East Cameron 124	100.00	%	Sept-12	Sept-17
Eugene Island 31	100.00	%	Oct-12	Oct-17
Ship Shoal 83	100.00	%	Oct-12	Oct-17
South Timbalier 110	100.00	%	Oct-12	Oct-17
Eugene Island 260	100.00	%	Nov-12	Nov-17
Ship Shoal 255	100.00	%	Dec-12	Dec-17
Ship Shoal 134 (Dry Hole)	100.00	%	(2)	(2)

(1) Farm-out. COI retains a 2.41% ORRI

(2) Purchased deep rights. Lease is held by production from shallow wells owned by third-party

Onshore Exploration and Properties

Kaybob Duvernay - Alberta, Canada

In April 2011, the Company announced a commitment to invest up to $20 million over two years in Alta Energy, a venture that will acquire, explore, develop and operate onshore unconventional oil and natural gas shale assets in North America. Contango has a 2.0% interest in Alta Energy. As of February 1, 2013, we had invested approximately $14.1 million in Alta Energy to purchase over 60,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. Alta Energy has built one of the largest acreage blocks in the core of the play. As of February 1, 2013, Alta Energy had drilled four vertical test wells and taken whole cores on two of those. Alta Energy has also successfully drilled two horizontal wells and anticipates completion by the end of March 2013. Alta Energy will continue to evaluate its drilling and completion program in 2013. We own a 2.0% interest in Alta Energy's non-Kaybob Duvernay projects, and a 5.0% interest in the Kaybob Duvernay project.

Jonah Field - Sublette County, Wyoming

In April 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the “LLC Agreement”) in connection with the formation of Exaro . Pursuant to the LLC Agreement, the Company had committed to invest up to $82.5 million in cash in Exaro over the next five years together with other parties for an aggregate commitment of $182.5 million, or a 45% ownership interest in Exaro.

In August 2012, one of the other investors in Exaro exercised its right to assume $15 million of the Company's commitment, which lowered the Company's commitment to $67.5 million and its ownership interest to 37%. As of December 31, 2012, the Company had invested approximately $33.8 million in Exaro.

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

As of December 31, 2012, the Exaro-Encana venture had 20 new drill wells on production plus an additional 12 wells that are either in the completion or fracture stimulation phase. We continue to have three drilling rigs running on this project. For the three and six months ended December 31, 2012, Exaro had income of approximately $1.3 million and $1.9 million, respectively, of which approximately $0.3 million and $0.5 million, respectively was recognized in the Company's consolidated statement of operations (net of taxes).

Tuscaloosa Marine Shale

In October 2012, the Company became a 25% non-operating working interest owner in property in the TMS operated by Goodrich. The TMS is an oil-focused shale play in central Louisiana and Mississippi. We have invested $4.3 million, net to Contango, to acquire acreage and participate in our first horizontal well, the Crosby 12H-1 well in Wilkinson County, Mississippi. For evaluation purposes, we drilled a pilot well, performed an open-hole evaluation and obtained a conventional core over the TMS interval.

The Crosby 12H-1 well was recently completed and as of February 6, 2013 was producing at a rate of 1,250 BOE per day and a 24 hour average rate of 1,130 BOE per day comprised of 1,050 barrels of oil and 469 Mcf of gas, on a 15/64" choke with 2,700 psi. The well, which has approximately 6,700 feet of usable lateral and was fracked with 25 stages, is in the early stage of flowback, with approximately 1% of the frac fluid recovered to date.

Additionally, as of February 1, 2013, the Company had invested approximately $9.0 million to lease approximately 24,000 acres in the TMS. We plan to participate in additional third-party operated wells with a small working interest prior to initiating an operated, high interest drilling program. The data we obtain from the Crosby 12H-1 well will help us evaluate our TMS acreage and develop a plan for drilling and operating future wells.

Employees

We have twelve employees. The Company outsources its human resources function to Insperity, Inc. and all of the Company’s employees are co-employees of Insperity, Inc.

Application of Critical Accounting Policies and Management’s Estimates

The discussion and analysis of the Company’s financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company’s significant accounting policies are described in Note 3 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 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 December 31, 2012 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense for the six months ended December 31, 2012 by approximately $1.0 million, $2.2 million and $3.5 million, respectively.

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

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

MD&A Summary Data

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

	Three Months Ended				
	December 31, 2011	March 31, 2012	June 30, 2012	September 30, 2012	December 31, 2012
Dutch and Mary Rose Wells	66.2	59.3	67.5	54.2	57.2
Ship Shoal 263 Well (Nautilus)	10.9	7.8	7.6	3.5	2.6
Vermilion 170 Well (Swimmy)	17.2	15.3	15.5	10.5	12.9
Non-operated wells	0.2	0.3	0.2	—	—
	94.5	82.7	90.8	68.2	72.7

Dutch and Mary Rose Wells

- The decrease in production during the three months ended March 31, 2012 was due to shutting in three of our wells for a total of 10 days for maintenance and to repair a small pipeline leak.
- The decrease in production during the three months ended September 30, 2012 was due to shutting in our Eugene Island 11 platform and seven of our wells for 12 days and shutting in the Eugene Island 24 platform and three of our wells for seven days due to flowline installation, problems at third-party, onshore facilities, and Hurricane Isaac evacuations. Additionally, our Dutch #4 well was shut-in for nine days to perform a workover, and our Mary Rose #4 well was shut-in for five days for flowline repairs.
- The decrease in production during the three months ended December 31, 2012 was due to shutting in our Dutch #1, #2 and #3 wells for 15 days to repair a pipeline leak and to reroute the wells from the Eugene Island 24 platform to our Eugene Island 11 platform. Additionally, our Eugene Island 11 platform was shut-in for one day for construction.
- As of February 1, 2013, these ten wells were flowing approximately 59.1 Mmcfed, net to Contango. This low rate is due to choking back Dutch #2 while waiting to plug back the lowest lobe in the CibOp formation in March 2013.

Ship Shoal 263 Well (Nautilus)

- Since December 31, 2011, production at this well has been slowly decreasing due to overheating, scaling problems, and water production. The well has also been shut-in several times over the past few months for production logging and chemical treatment. We believe that this well may be fully depleted within the next year. Despite this, the well reached payout during fiscal year 2012. We will continue producing this well as long as it is economical. As of February 1, 2013, the well was flowing at approximately 1.2 Mmcfed, net to Contango.
- In September 2012, due to the decline in production from this well, our reservoir engineer revised his estimated net proved natural gas and oil reserves from this well. As a result, the net book value of our Ship Shoal 263 well exceeded the future undiscounted cash flows associated with its reserves. Accordingly, the Company recognized an impairment expense of approximately $6.3 million for the three months ended September 30, 2012. During the three months ended December 31, 2012, due to the continued decline in production, our reservoir engineer again revised his estimated net proved natural gas and oil reserves from this well. As a result, the Company recognized an additional impairment expense of approximately $5.7 million for the three months ended December 31, 2012 for the difference between the net book value of Ship Shoal 263 and the fair value of its reserves. For the six months ended December 31, 2012, the Company recognized an impairment expense of approximately $12.0 million related to this well.

Vermilion 170 Well (Swimmy)

- Our Vermilion 170 well was shut-in for a total of five days during the three months ended September 30, 2012 for Hurricane Isaac evacuations, high pipeline pressures due to pigging operations, equipment testing, and an additional 13 days for compressor installation.
- In late January 2013 we encountered a downhole problem at Swimmy and shut-in the well. We have scheduled a workover to replace downhole tubing and expect the well to resume production by mid-March 2013.

The table below sets forth revenue, expense and production data for the three and six months ended December 31, 2012 and 2011:

	Three Months Ended December 31,			Six Months Ended December 31,		
	2012	2011	Change	2012	2011	Change
	(thousands, except percent change, average sales price and selected data per Mcfe)					
Revenues:						
Natural gas sales	$17,970	$22,161	(19)%	$32,047	$44,423	(28)%
Condensate sales	$10,411	$20,699	(50)%	$21,093	$34,403	(39)%
NGL sales	$6,559	$11,047	(41)%	$11,565	$19,283	(40)%
Total revenues	$34,940	$53,907	(35)%	$64,705	$98,109	(34)%
Production:						
Natural gas (million cubic feet)	5,096	6,552	(22)%	9,863	11,729	(16)%
Oil and condensate (thousand barrels)	97	179	(46)%	199	307	(35)%
Natural gas liquids (thousand gallons)	7,057	7,694	(8)%	13,344	13,404	*
Total (million cubic feet equivalent)	6,686	8,725	(23)%	12,963	15,486	(16)%
Natural gas (million cubic feet per day)	55.4	71.2	(22)%	53.6	63.7	(16)%
Oil and condensate (thousand barrels per day)	1.1	1.9	(46)%	1.1	1.7	(35)%
Natural gas liquids (thousand gallons per day)	76.7	83.6	(8)%	72.5	72.8	*
Total (million cubic feet equivalent per day)	72.7	94.5	(23)%	70.5	84.3	(16)%
Average Sales Price:						
Natural gas (per thousand cubic feet)	$3.53	$3.38	4 %	$3.25	$3.79	(14)%
Oil and condensate (per barrel)	$107.20	$115.46	(7)%	$106.24	$112.08	(5)%
Natural gas liquids (per gallon)	$0.93	$1.44	(35)%	$0.87	$1.44	(40)%
Total (per thousand cubic feet equivalent)	$5.23	$6.18	(15)%	$4.99	$6.34	(21)%
Summary of Financial Information:						
Operating expenses	$4,973	$7,010	(29)%	$11,435	$12,899	(11)%
Exploration expenses	$6,629	$33	**	$51,614	$56	**
Depreciation, depletion and amortization	$10,770	$13,536	(20)%	$20,336	$24,493	(17)%
Impairment of natural gas and oil properties	$5,668	$—	100 %	$14,078	$—	100 %
General and administrative expenses	$2,818	$2,304	22 %	$5,398	$4,552	19 %
Selected Data per Mcfe:						
Lease operating expenses	$0.87	$0.80	9 %	$0.88	$0.83	6 %
General and administrative expenses	$0.42	$0.26	62 %	$0.42	$0.29	45 %
Depreciation, depletion and amortization of natural gas and oil properties	$1.60	$1.53	5 %	$1.55	$1.56	(1)%

* Less than 1%
** Greater than 100%

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

Natural Gas, Oil and Natural Gas Liquids (“NGL”) Sales and Production. We reported revenues of approximately $34.9 million for the three months ended December 31, 2012, compared to revenues of approximately $53.9 million for the three months ended December 31, 2011. This decrease in revenues of $19.0 million was principally attributable to a decrease in natural gas, condensate and NGL production, further compounded by lower average equivalent sales prices.

Our net natural gas production for the three months ended December 31, 2012 was approximately 55.4 Mmcfd, down from approximately 71.2 Mmcfd for the three months ended December 31, 2011. Net oil and condensate production for the comparable periods also decreased from approximately 1,900 barrels per day to approximately 1,100 barrels per day, and our NGL production decreased from approximately 83,600 gallons per day to approximately 76,700 gallons per day. In total, equivalent production decreased from 94.5 Mmcfed to 72.7 Mmcfed.

For the three months ended December 31, 2012, natural gas accounted for approximately 76% of our production, while condensate and NGLs accounted for 9% and 15%, respectively. From a revenue perspective however, natural gas generated 51% of our revenues, while condensate and NGLs generated 30% and 19%, respectively. For the three months ended December 31, 2011, natural gas accounted for 75% of our production, while condensate and NGLs accounted for 12% and 13%, respectively. From a revenue perspective however, natural gas generated 41% of our revenues, while condensate and NGLs generated 38% and 21%, respectively.

Average Sales Prices. For the three months ended December 31, 2012, the average price of natural gas was $3.53 per thousand cubic feet ("Mcf"), the average price for oil and condensate was $107.20 per barrel and the average price for NGLs was $0.93 per gallon. For the three months ended December 31, 2011, the average price of natural gas was $3.38 per Mcf, the average price for oil and condensate was $115.46 per barrel and the average price for NGLs was $1.44 per gallon.

Operating Expenses. Lease operating expenses ("LOE") for the three months ended December 31, 2012 were approximately $5.0 million, as compared to $7.0 million for the three months ended December 31, 2011. This decrease in LOE is partly attributable to a decrease in overall production during the period.

Exploration Expense. We reported approximately $6.6 million of exploration expense for the three months ended December 31, 2012, which consists mainly of $6.3 million for Eagle and Fang, $0.2 million for an unsuccessful drilling program in Jim Hogg County, Texas, and $0.1 million in geological and geophysical activities, seismic data and delay rentals. For the three months ended December 31, 2011, we reported approximately $33,000 of exploration expense, which consists mainly of expenses for geological and geophysical activities, seismic data and delay rentals.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the three months ended December 31, 2012 was approximately $10.8 million. For the three months ended December 31, 2011, we recorded approximately $13.5 million of depreciation, depletion and amortization. The decrease in depreciation, depletion and amortization was primarily attributable to a decrease in overall production.

Impairment of Natural Gas and Oil Properties. For the three months ended December 31, 2012, the Company recorded impairment expense of $5.7 million related to our Ship Shoal 263 well. For the three months ended December 31, 2011, the Company did not record any impairment expenses.

General and Administrative Expenses. General and administrative expenses for the three months ended December 31, 2012 and the three months ended December 31, 2011 were approximately $2.8 million and $2.3 million, respectively. Major components of general and administrative expenses for the three months ended December 31, 2012 included approximately $0.2 million in State of Louisiana franchise taxes, $1.3 million in salaries and benefits, $0.9 million in accounting, tax, legal, engineering and other professional fees, $0.1 million in insurance costs, $0.1 million in other administrative costs, and $0.2 million related to board of director compensation.

Major components of general and administrative expenses for the three months ended December 31, 2011 included approximately $0.1 million in State of Louisiana franchise taxes, $1.6 million in salaries and benefits, $0.3 million in accounting, tax, legal, engineering and other professional fees, $0.1 million in insurance costs, and $0.1 million related to board of director compensation.

Six Months Ended December 31, 2012 Compared to Six Months Ended December 31, 2011

Natural Gas, Oil and Natural Gas Liquids ("NGL") Sales and Production. We reported revenues of approximately $64.7 million for the six months ended December 31, 2012, compared to revenues of approximately $98.1 million for the six months ended December 31, 2011. This decrease in revenues of $33.4 million was principally attributable to a decrease in natural gas, condensate and NGL production, further compounded by lower sales prices for all of our products.

Our net natural gas production for the six months ended December 31, 2012 was approximately 53.6 Mmcfd, down from approximately 63.7 Mmcfd for the six months ended December 31, 2011. Net oil and condensate production for the comparable periods also decreased from approximately 1,700 barrels per day to approximately 1,100 barrels per day, and our NGL production decreased from approximately 72,800 gallons per day to approximately 72,500 gallons per day. In total, equivalent production decreased from 84.3 Mmcfed to 70.5 Mmcfed.

For the six months ended December 31, 2012, natural gas accounted for approximately 76% of our production, while condensate and NGLs accounted for 9% and 15%, respectively. From a revenue perspective however, natural gas generated 50% of our revenues, while condensate and NGLs generated 32% and 18%, respectively. For the six months ended December 31, 2011, natural gas accounted for 76% of our production, while condensate and NGLs accounted for 12% and 12%, respectively. From a revenue perspective however, natural gas generated 45% of our revenues, while condensate and NGLs generated 35% and 20%, respectively.

Average Sales Prices. For the six months ended December 31, 2012, the average price of natural gas was $3.25 per thousand cubic feet ("Mcf"), the average price for oil and condensate was $106.24 per barrel and the average price for NGLs was $0.87 per gallon. For the six months ended December 31, 2011, the average price of natural gas was $3.79 per Mcf, the average price for oil and condensate was $112.08 per barrel and the average price for NGLs was $1.44 per gallon.

Operating Expenses. Lease operating expenses ("LOE") for the six months ended December 31, 2012 were approximately $11.4 million, as compared to approximately $12.9 million for the six months ended December 31, 2011. This decrease in LOE is partly attributable to a decrease in overall production during the period.

Exploration Expense. We reported approximately $51.6 million of exploration expense for the six months ended December 31, 2012, which consists mainly of $50.0 million for Eagle and Fang, $1.4 million related to an unsuccessful drilling program in Jim Hogg County, Texas and $0.2 million for geological and geophysical activities, seismic data and delay rentals. For the six months ended December 31, 2011, we reported approximately $56,000 of exploration expense, which consists mainly of expenses for geological and geophysical activities, seismic data and delay rentals.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the six months ended December 31, 2012 was approximately $20.3 million. For the six months ended December 31, 2011, we recorded approximately $24.5 million of depreciation, depletion and amortization. The decrease in depreciation, depletion and amortization was primarily attributable to a decrease in overall production.

Impairment of Natural Gas and Oil Properties. For the six months ended December 31, 2012, the Company recorded impairment expense of approximately $14.1 million on our properties. Of this amount, approximately $12.0 million related to our Ship Shoal 263 well and $2.1 million related to the Eugene Island 24 platform and other properties. For the six months ended December 31, 2011, the Company did not record any impairment expenses.

General and Administrative Expenses. General and administrative expenses for the six months ended December 31, 2012 and the six months ended December 31, 2011 were approximately $5.4 million and $4.6 million, respectively. Major components of general and administrative expenses for the six months ended December 31, 2012 included approximately $0.4 million in State of Louisiana franchise taxes, $2.5 million in salaries and benefits, $1.7 million in accounting, tax, legal, engineering and other professional fees, $0.2 million in insurance costs, $0.3 million in other administrative costs, and $0.3 million related to board of director compensation.

Major components of general and administrative expenses for the six months ended December 31, 2011 included approximately $0.3 million in State of Louisiana franchise taxes, $3.1 million in salaries and benefits, $0.8 million in accounting, tax, legal, engineering and other professional fees, $0.2 million in insurance costs, and $0.2 million related to board of director compensation.

Capital Resources and Liquidity

Cash From Operating Activities. Cash flows from operating activities provided approximately $46.9 million in cash for the six months ended December 31, 2012 compared to $32.7 million for the same period in 2011. This increase in cash provided by operating activities was mainly attributable to the timing of payments of the Company's obligations.

Cash From Investing Activities. Cash flows used in investing activities for the six months ended December 31, 2012 were approximately $62.0 million, which consisted mainly of $68.6 million in capital expenditures for drilling and developing wells ($50.0 million of this was Eagle and Fang), investing $1.5 million in Alta Energy, partially offset by receiving $7.5 million as a return of capital related to our Exaro investment and $0.6 million as a distribution from REX to its partners. Cash flows used in investing activities for the six months ended December 31, 2011 were approximately $13.6 million, which consisted mainly of capital expenditures for developing our wells and facilities.

Cash From Financing Activities. Cash flows used in financing activities for the six months ended December 31, 2012 were $35.5 million, compared to approximately $17.0 million of cash used for the six months ended December 31, 2011. This increase in cash used is attributable to paying a $30.5 million dividend to shareholders in 2012 and purchasing shares of common stock under our publicly announced share repurchase programs.

Capital Budget. Our capital expenditure budget for the next twelve months calls for us to invest approximately $37.0 million from cash on hand and operating cash flows, as follows:

• $20.0 million to drill one wildcat exploration well in the Gulf of Mexico.
• $11.0 million in Exaro Energy III LLC.
• $2.0 million in Alta Energy.
• $4.0 million to complete installing compression on our Eugene Island 11.

Should the Company have exploration success with its exploration well, our capital expenditure budget will be significantly increased.

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

Natural Gas and Oil Reserves

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

• Over 30 years of practical experience in the estimation and evaluation of reserves
• A registered professional engineer in the State of Texas
• Bachelor of Science Degree in Petroleum Engineering
• Member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

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

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

	Proved Reserves as of	
	December 31, 2012	June 30, 2012
Natural Gas (MMcf)	174,032	201,379
Oil, Condensate and Natural Gas Liquids (MBbls)	7,844	9,198

Total proved reserves (Mmcfe)	221,096	256,567

Our proved reserves as of December 31, 2012 were approximately 35.5 billion cubic feet equivalent (“Bcfe”) less than our proved reserves as of June 30, 2012. The major contributors to this decrease include normal production of 13 Bcfe during the six months ended December 31, 2012, a 9.2 Bcfe decrease in our Ship Shoal 263 reserves estimates, and an 11.5 Bcfe decrease in our Vermilion 170 reserves estimates, as determined by our reservoir engineer.

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

Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program which concluded in October 2011. Under this program, the Company purchased approximately 2.2 million shares, at an average price of $46.35 per share. All shares were purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases were made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes.

$50 Million Share Repurchase Program

In September 2011, the Company's Board of Directors approved the adoption of a $50 million share repurchase program, effective upon completion of purchases under the Company's $100 million share repurchase program. The repurchases will be subject to the same terms and conditions as repurchases made under the $100 million share repurchase program. During the three and six months ended December 31, 2012, the Company purchased 97,496 shares at an average price of $50.82 per share, for a total of approximately $5.0 million. During the three and six months ended December 31, 2011, the Company purchased 35,663 shares at an average price of $54.58 per share, for a total of approximately $1.9 million. As of February 1, 2013, the Company had purchased 197,877 shares under the $50 million share repurchase program at an average price of $52.16 per share, plus 45,000 stock options, all for approximately $10.8 million.

As of February 1, 2013, under both share repurchase programs combined, the Company had purchased approximately 2.4 million shares of its common stock at an average cost per share of $46.84 and 45,000 stock options, for a total of approximately $110.8 million, bringing its total share count to 15,194,952 shares of common stock outstanding.

Credit Facility

In October 2010, the Company completed the arrangement of a $40 million secured revolving credit agreement with Amegy Bank (the "Credit Agreement"). The Credit Agreement is supported by a hydrocarbon borrowing base and is available to fund the Company's exploration and development activities, as well as repurchase shares of common stock and to fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. Any principal borrowed is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and effective November 1, 2011, a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of February 1, 2013, the Company was in compliance with all covenants and had no borrowings outstanding under the Credit Agreement.

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 expressi identify forward-looking statements and express our expectations about future events. These include such matters as:

- Our financial position
- Business strategy, including outsourcing
- Meeting our forecasts and budgets

- Anticipated capital expenditures
- Drilling of wells
- Natural gas and oil production and reserves
- Timing and amount of future discoveries (if any) and production of natural gas and oil
- Operating costs and other expenses
- Cash flow and anticipated liquidity
- Prospect development
- Property acquisitions and sales
- New governmental laws and regulations
- Expectations regarding oil and gas markets in the United States

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

- Low and/or declining prices for natural gas and oil
- Natural gas and oil price volatility
- Operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and gas processing facilities
- The risks associated with acting as the operator in drilling deep high pressure and temperature wells in the Gulf of Mexico, including well blowouts and explosions
- The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which the Company has made a large capital commitment relative to the size of the Company's capitalization structure
- The timing and successful drilling and completion of natural gas and oil wells
- Availability of capital and the ability to repay indebtedness when due
- Availability of rigs and other operating equipment
- Ability to receive Bureau of Ocean Energy Management, Regulation and Enforcement permits on a time schedule that permits the Company to operate efficiently
- Ability to raise capital to fund capital expenditures
- Timely and full receipt of sale proceeds from the sale of our production
- The ability to find, acquire, market, develop and produce new natural gas and oil properties
- Interest rate volatility
- Zero or near zero interest rates
- Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures
- Operating hazards attendant to the natural gas and oil business
- Downhole drilling and completion risks that are generally not recoverable from third parties or insurance
- Potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps
- Weather
- Availability and cost of material and equipment
- Delays in anticipated start-up dates
- Actions or inactions of third-party operators of our properties
- Actions or inactions of third-party operators of pipelines or processing facilities
- The ability to find and retain skilled personnel
- Strength and financial resources of competitors
- Federal and state regulatory developments and approvals
- Environmental risks

- Worldwide economic conditions
- The ability to construct and operate offshore infrastructure, including pipeline and production facilities
- The continued compliance by the Company with various pipeline and gas processing plant specifications for the gas and condensate produced by the Company
- Operating costs, production rates and ultimate reserve recoveries of our offshore discoveries
- 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.

Risk Factors

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

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

Our revenues, profitability and future growth depend significantly on natural gas and crude oil prices. Prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. We do not expect to hedge our production to protect against price decreases. Lower prices may also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

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

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

We 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 have entered into a First Right Agreement with JEX, whereby JEX granted a first right of refusal to Contango to purchase any exploration prospects generated and recommended by JEX. Prospects will be presented along with terms and conditions for purchasing each prospect and Contango shall have the first right of refusal to purchase the prospect from JEX for a period of 10 days, subject to mutually acceptable terms. Pursuant to the First Right Agreement, JEX will be paid an annual fee of $0.5 million.

Highly qualified explorationists and engineers are difficult to attract and retain. As a result, the loss of the services of JEX could have a material adverse effect on us and could prevent us from pursuing our business plan. Additionally, the loss by JEX of certain explorationists could have a material adverse effect on our operations as well. We have historically entered into agreements with JEX and its affiliates when we purchase prospects from JEX and its affiliates that specify the terms and conditions of purchase.

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

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

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 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.

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

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

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

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

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

The majority of our capital investments is focused in offshore Gulf of Mexico exploration prospects, which may result in a total loss of our investment. Furthermore, even our productive wells may not result in profitable operations. Gulf of Mexico exploration efforts have been undertaken for over 60 years and remaining prospects are at deeper horizons that are more expensive to drill and often in much deeper water depths. Accordingly, as a result, a number of companies have shifted their focus to onshore “shale plays.” The Company’s continuing focus on the Gulf of Mexico will result in significant dry hole costs, perhaps in excess of $30 million for one well, which significantly concentrates and increases our risk profile.

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

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

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

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

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

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

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

Approximately 89% of our proved reserves are assigned to our Dutch and Mary Rose discoveries which have ten producing well bores concentrated in one reservoir and are producing through two production platforms. Reserve assessments based on only ten well bores in one reservoir are subject to significantly greater risk of being shut-in for a variety of weather, platform and pipeline difficulties. In addition, the risk of a downward revision in our reserve estimates is also greater.

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

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

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

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

- Unexpected drilling conditions.
- Blowouts, fires or explosions with resultant injury, death or environmental damage.
- Pressure, temperature or other irregularities in formations.
- Equipment failures and/or accidents caused by human error.
- Tropical storms, hurricanes and other adverse weather conditions.
- Compliance with governmental requirements and laws, present and future.
- Shortages or delays in the availability of drilling rigs and the delivery of equipment.
- Problems at third-party operated platforms, pipelines and gas processing facilities over which we have no control.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would materially and adversely affect our future cash flows and results of operations. In addition, as a "successful efforts" company, we choose to account for unsuccessful exploration efforts (the drilling of "dry holes") and seismic costs as a current expense of operations, which immediately impacts our earnings. Significant expensed exploration charges in any period would materially adversely affect our earnings for that period and cause our earnings to be volatile from period to period.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Not hedging our production may result in losses.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

As a result of the Deepwater Horizon Incident of 2010, the Department of the Interior issued additional safety and performance standards as well as rigorous monitoring and testing requirements for offshore drilling. In addition, various Congressional committees began pursuing legislation to regulate drilling activities, establish safety requirements and increase liability for oil spills.

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

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

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

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

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

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

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

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

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. They are responsible for leading the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well design and workplace safety to corporate accountability. One of the many reforms includes implementing a SEMS program. This program requires operators to identify, address, and manage safety and environmental hazards during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. Failure to comply with the SEMS program may force us to cease operations in the Gulf of Mexico.

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

In addition to the enforcement actions specified above, the BSEE can assess a civil penalty of up to $40,000 per violation per day if: 1) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or 2) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

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

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

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

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

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

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

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

- Timing and amount of capital expenditures.
- The operator’s expertise and financial resources.

- Approval of other participants in drilling wells.
- Selection of technology.

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

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

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

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

- Recoverable reserves.
- Exploration potential.
- Future natural gas and oil prices.
- Operating costs.
- Potential environmental and other liabilities and other factors.
- Permitting and other environmental authorizations required for our operations.

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

- Problems integrating the purchased operations, personnel or technologies.
- Unanticipated costs.
- Diversion of resources and management attention from our exploration business.
- Entry into regions or markets in which we have limited or no prior experience.
- Potential loss of key employees of the acquired organization.

Anti-takeover provisions of our certificate of incorporation, bylaws and Delaware law could adversely affect 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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate and Credit Rating Risk. As of February 1, 2013, we had no long-term debt subject to the risk of loss associated with movements in interest rates.

As of December 31, 2012, we had approximately $79.5 million in cash and cash equivalents, all of which was held in non-interest bearing accounts. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings.

Based on a sensitivity analysis performed on the financial instruments held as of December 31, 2012, an immediate 10% change in interest rates is not expected to have a material effect on our near-term financial condition or results of operations.

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas and oil production. Realized commodity prices received for our production are the spot prices applicable to natural gas and crude oil. Prices received for natural gas and oil are volatile and unpredictable and are beyond our control. For the three and six months ended December 31, 2012, a 10% fluctuation in the prices received for natural gas and oil production would impact our revenues by approximately $3.5 million and $6.5 million, respectively.

Item 4. Controls and Procedures

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

There were no changes in the Company's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2012 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 November 29, 2012, the Board of the Company declared a special dividend of $2.00 per share of common stock which was paid on December 17, 2012 to each holder of record of the Company's common stock as of the close of business on December 10, 2012.

Item 6. Exhibits

(a) Exhibits:

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

Exhibit Number	Description
3.1	Certificate of Incorporation of Contango Oil & Gas Company. (1)
3.2	Bylaws of Contango Oil & Gas Company. (1)
3.3	Agreement of Plan of Merger of Contango Oil & Gas Company, a Delaware corporation, and Contango Oil & Gas Company, a Nevada corporation. (1)
3.4	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company. (2)
4.1	Facsimile of common stock certificate of Contango Oil & Gas Company. (3)
10.1	Second Amended and Restated Credit Agreement dated as of October 1, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association, as Administrative Agent and Letter of Credit Issuer, together with First Amendment to Second Amended and Restated Credit Agreement dated October 20, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association. (4)
10.2	Purchase and Sale Agreement between Juneau Exploration, L.P. and Contango Operators, Inc. dated October 1, 2010. (5)
10.3	First Amended and Restated Limited Liability Company Agreement of Exaro Energy III LLC dated as of March 31, 2012. (6)
10.4	Advisory Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., dated as of April 1, 2012. (7)
10.5	Termination of Advisory Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., dated as of April 1, 2012. †
10.6	First Right of Refusal Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., entered into as of January 1, 2013. †
10.7	Advisory Agreement between Contaro Company and Juneau Exploration, L.P., entered into as of January 1, 2013. †
23.1	Consent of William M. Cobb & Associates, Inc. †
31.1	Certification of Acting 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 Acting Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
101	Interactive Data Files †

† Filed herewith.

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

6. Filed as an exhibit to the Company's report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012.

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

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: February 11, 2013	By: /S/ JOSEPH J. ROMANO Joseph J. Romano President and Chief Executive Officer (Principal Executive Officer)
Date: February 11, 2013	By: /S/ SERGIO CASTRO Sergio Castro Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)
Date: February 11, 2013	By: /S/ YAROSLAVA MAKALSKAYA Yaroslava Makalskaya Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)

38