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.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY REPORT ON FORM 10-Q
FOR THE SIX MONTHS ENDED DECEMBER 31, 2012
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All references in this Form 10-Q to the "Company", "Contango", "we", "us" or "our" are to Contango Oil & Gas Company and its wholly-owned subsidiaries. Unless otherwise noted, all information in this Form 10-Q relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

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

	December 31, 2012 (thousands)	June 30, 2012
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

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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.

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):

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	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

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)%