CONTANGO OIL & GAS CO
Form 10-Q
August 07, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2015

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.)

717 TEXAS, SUITE 2900

HOUSTON, TEXAS	77002
(Address of principal executive offices)	(Zip Code)

(713) 236-7400

(Registrant's telephone number, including area code)

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

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

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

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

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

The total number of shares of common stock, par value $0.04 per share, outstanding as of August 6, 2015 was 19,420,030.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE SIX MONTHS ENDED JUNE 30, 2015

TABLE OF CONTENTS

All references in this Quarterly Report on Form 10-Q to the "Company", "Contango", "we", "us" or "our" are to Contango Oil Gas Company and its subsidiaries.

Item 1. Consolidated Financial Statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	June 30, 2015	December 31, 2014
	(unaudited)	
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	23,171	25,309
Prepaid expenses and other	3,115	1,941
Inventory	1,087	2,166
Current deferred tax asset	1,239	1,624
Total current assets	28,612	31,040
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,177,817	1,138,054
Unproved properties	32,829	35,783
Other property and equipment	1,126	1,084
Accumulated depreciation, depletion and amortization	(501,286)	(426,298)
Total property, plant and equipment, net	710,486	748,623
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	61,918	62,085
Other	1,365	1,667
Total other non-current assets	63,283	63,752
TOTAL ASSETS	$ 802,381	$ 843,415
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 60,047	$ 92,892
Current derivative liability	10	—
Current asset retirement obligations	4,925	4,123
Total current liabilities	64,982	97,015

NON-CURRENT LIABILITIES:		
Long-term debt	111,402	63,359
Deferred tax liability	72,409	93,952
Asset retirement obligations	21,643	21,623
Total non-current liabilities	205,454	178,934
Total liabilities	270,436	275,949
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 24,645,140 shares issued and 19,420,246 shares outstanding at June 30, 2015, 24,372,538 shares issued and 19,148,000 shares outstanding at December 31, 2014	974	963
Additional paid-in capital	235,846	233,278
Treasury shares at cost (5,224,894 shares at June 30, 2015 and 5,224,538 shares at December 31, 2014)	(127,533)	(127,525)
Retained earnings	422,658	460,750
Total shareholders' equity	531,945	567,466
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 802,381	$ 843,415

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

3

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(unaudited)		(unaudited)	
REVENUES:				
Oil and condensate sales	$ 15,688	$ 38,340	$ 26,382	$ 73,440
Natural gas sales	15,287	31,244	32,110	65,871
Natural gas liquids sales	4,359	8,835	7,489	19,365
Total revenues	35,334	78,419	65,981	158,676
EXPENSES:				
Operating expenses	10,972	11,576	20,883	22,629
Exploration expenses	6,924	10,853	11,407	37,784
Depreciation, depletion and amortization	38,770	39,901	73,885	74,303
Impairment and abandonment of oil and gas properties	236	1,371	2,517	16,566
General and administrative expenses	7,351	9,207	15,179	19,664
Total expenses	64,253	72,908	123,871	170,946
OTHER INCOME (EXPENSE):				
Gain (loss) from investment in affiliates (net of income taxes)	(745)	1,478	(187)	3,100
Interest expense	(835)	(737)	(1,530)	(1,405)
Loss on derivatives, net	(10)	(1,263)	(10)	(3,222)
Other income (expense)	995	(196)	990	(196)
Total other income (expense)	(595)	(718)	(737)	(1,723)
NET INCOME (LOSS) BEFORE INCOME TAXES	(29,514)	4,793	(58,627)	(13,993)
Income tax benefit (provision)	9,986	(212)	20,535	8,381
NET INCOME (LOSS)	$ (19,528)	$ 4,581	$ (38,092)	$ (5,612)
NET INCOME (LOSS) PER SHARE:				
Basic	$ (1.03)	$ 0.24	$ (2.01)	$ (0.29)
Diluted	$ (1.03)	$ 0.24	$ (2.01)	$ (0.29)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	18,939	19,074	18,939	19,073
Diluted	18,939	19,130	18,939	19,073

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Six Months Ended June 30, 2015	2014
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (38,092)	$ (5,612)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	73,885	74,303
Impairment of natural gas and oil properties	2,544	15,592
Exploration expenses	9,011	36,755
Deferred income taxes	(21,159)	(6,901)
Loss on sale of assets	231	—
Loss (gain) from investment in affiliates	288	(4,770)
Stock-based compensation	2,578	2,115
Unrealized loss on derivative instruments	10	469
Changes in operating assets and liabilities:		
Decrease in accounts receivable and other receivables	2,024	15,649
Increase in prepaid expenses	(1,173)	(1,692)
Increase (decrease) in accounts payable and advances from joint owners	(22,145)	2,050
Increase (decrease) in other accrued liabilities	(523)	160
Decrease in income taxes receivable, net	470	58
Other	802	(328)
Net cash provided by operating activities	$ 8,751	$ 127,848
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (56,786)	$ (109,271)
Distributions from affiliates	—	5,365
Net cash used in investing activities	$ (56,786)	$ (103,906)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 218,267	$ 233,973
Repayments under credit facility	(170,225)	(257,996)
Proceeds from exercised options	—	118
Purchase of treasury stock	(7)	—

Debt issuance costs	—	(37)
Net cash provided by (used in) financing activities	$ 48,035	$ (23,942)
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ —	$ —
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ —

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(in thousands, except number of shares)

	Common Stock Shares	Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
	(unaudited)					
Balance at December 31, 2014	19,148,000	$ 963	$ 233,278	$ (127,525)	$ 460,750	$ 567,466
Treasury shares at cost	(356)	—	—	(8)	—	(8)
Restricted shares activity	272,602	11	(10)	—	—	1
Stock-based compensation	—	—	2,578	—	—	2,578
Net loss	—	—	—	—	(38,092)	(38,092)
Balance at June 30, 2015	19,420,246	$ 974	$ 235,846	$ (127,533)	$ 422,658	$ 531,945

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, "Contango" or the "Company") is a Houston, Texas based, independent oil and natural gas company. The Company's business is to maximize production and cash flow from its onshore properties in various plays and offshore properties in the shallow waters of the Gulf of Mexico ("GOM"), and to use that cash flow to explore, develop, exploit and acquire crude oil and natural gas properties in the onshore Texas Gulf Coast and Rocky Mountain regions of the United States.

The following table lists the Company's primary producing areas as of June 30, 2015:

Location	Formation
Gulf of Mexico	Offshore Louisiana – water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Zavala and Dimmitt counties, Texas	Buda / Austin Chalk
Weston County, Wyoming	Muddy Sandstone
Texas Gulf Coast	Conventional formations
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC ("Exaro"). Production from this entity is not included in the Company's production results for the three or six months ended June 30, 2015, or in its reported reserves as of December 31, 2014.

The Company intends to grow reserves and production by further exploiting the unproved resource potential on its existing onshore property base with specific activity in any particular area or time, to be a function of drilling success, commodity prices and/or prevailing service costs. In addition, the Company owns developed and undeveloped acreage in several regions that it believes provides additional unproved resource potential that could provide significant long-term growth in production and reserves.

Due to the current challenging commodity price environment, the Company is focusing its 2015 capital program on: (i) the preservation of its strong and flexible financial position, including limiting its overall capital expenditure budget; (ii) dedicating capital primarily to de-risking and/or delineating strategic projects (i.e. versus field development); (iii) the identification of opportunities for cost and production efficiencies in all areas of its operations; and (iv) continuing to identify and, when appropriate, pursue the expansion of its resource potential through opportunistic acquisitions. No drilling activity is planned for the GOM in 2015.

The following table lists the areas to which the Company has budgeted to allocate capital during 2015:

Location	Formation
Madison and Grimes counties, Texas	Woodbine (Upper and Lower Lewisville)
Weston County, Wyoming	Muddy Sandstone
Fayette and Gonzales counties, Texas	Navarro / Buda / Austin Chalk

2. Summary of Significant Accounting Policies

The accounting policies followed by the Company are set forth in the notes to the Company's audited consolidated financial statements included in its Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K") filed with the Securities and Exchange Commission ("SEC"). Please refer to the notes to the financial statements included in the 2014 Form 10-K for additional details of the Company's financial condition, results of operations and cash flows. No material items included in those notes have changed except as a result of normal transactions in the interim or as disclosed within this report.

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 SEC, including instructions to Quarterly Reports on 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 2014 Form 10-K. The consolidated results of operations for the six months ended June 30, 2015 are not necessarily indicative of the results that may be expected for the year ending December 31, 2015.

The Company's consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. All wholly-owned subsidiaries are consolidated. Partially-owned oil and gas exploration and development affiliates which are not controlled by the Company, such as Republic Exploration LLC ("REX"), are proportionately consolidated. The investment in Exaro by our wholly-owned subsidiary, Contaro Company ("Contaro") is accounted for using the equity method of accounting, and therefore, the Company does not include its share of individual operating results or production in those reported for the Company's consolidated results.

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 risk adjusted proved, probable and possible reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair value. No impairment of proved properties was recognized for the three months ended June 30, 2015. The Company recognized a $2.0 million impairment of small marginal natural gas properties for the six months ended June 30, 2015. No impairment of proved properties was recognized for the three and six months ended June 30, 2014.

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. The Company recognized impairment expense of approximately $0.3 million, for the three months ended June 30, 2015. For the six months ended June 30, 2015, the Company recognized impairment expense of approximately $0.5 million related to impairment and partial impairment of certain unproved properties due to expiring leases.

On April 29, 2014, the Company reached total depth on its Ship Shoal 255 well, and no commercial hydrocarbons were found. As a result, for the three months ended June 30, 2014, the Company recognized $10.1 million in exploration expenses for the cost of drilling the well and $0.5 million in impairment expense for the associated platform located in Block Ship Shoal 263. For the six months ended June 30, 2014, the Company recognized a total of $36.8 million in exploration expense for the cost of drilling the well and $15.6 million in impairment expense, including $3.5 million related to leasehold costs and $12.1 million related to the platform located at Block Ship Shoal 263, which was expected to be used by the Ship Shoal 255 well, had it been successful.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share is computed by dividing income (loss) attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For the three months ended June 30, 2014, the weighted average incremental shares for stock options was 7,264 shares and the weighted average incremental shares for restricted stock was 48,257 shares. Potential dilutive securities, including unexercised stock options and unvested restricted stock, have not been considered when their effect would be antidilutive. For the three and six months ended June 30, 2015, 129,347 stock options and 481,422 restricted shares were excluded from dilutive shares due to the loss for the period. For the three months ended June 30, 2014, 94,914 shares were excluded from dilutive shares as they were antidilutive. For the six months ended June 30, 2014, 130,639 stock options and 287,792 restricted shares were excluded from the dilutive shares due to the loss for the period.

Subsidiary Guarantees

Contango Oil & Gas Company, as the parent company (the “Parent Company”), has filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Any such debt securities would likely be guaranteed on a full and unconditional basis by each of Crimson Exploration Inc., Crimson Exploration Operating, Inc., Contango Energy Company, Contango Operators, Inc., Contango Mining Company, Conterra Company, Contaro Company, Contango Alta Investments, Inc., Contango Venture Capital Corporation and any other of our future subsidiaries specified in any future prospectus supplement (each a “Subsidiary Guarantor”). Each of the Subsidiary Guarantors is wholly-owned by the Parent Company, either directly or indirectly. The Parent Company has no assets or operations independent of the Subsidiary Guarantors, and there are no significant restrictions upon the ability of the Subsidiary Guarantors to distribute funds to the Parent Company. The Parent Company has one wholly-owned subsidiary that is inactive and not a Subsidiary Guarantor. Finally, the Parent Company’s wholly-owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

Recent Accounting Pronouncements

In June 2015, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update No. 2015-10: Technical Corrections and Improvements (ASU 2015-10). ASU 2015-10 is part of an initiative to clarify the Accounting Standards Codification (Codification), correct unintended application of guidance, and make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost to most entities. ASU 2015-10 covers a wide range of topics in the Codification and is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015; early adoption is permitted. The Company is currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on its financial position and results of operations.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03: Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03). ASU 2015-03 is part of an initiative to reduce complexity in accounting standards. This update simplifies the presentation of debt issuance costs, by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance of debt issuance costs are not affected by the amendments in this update. An entity should apply the new guidance on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. ASU 2015-03 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015; early application is permitted for financial statements that have not been previously issued. The provisions of this accounting update are not expected to have a material impact on the Company's financial position or results of operations.

In January 2015, the FASB issued Accounting Standards Update No. 2015-01: Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items (ASU 2015-01). ASU 2015-01 is part of an initiative to reduce complexity in accounting standards. This update eliminates from generally accepted accounting principles the concept of extraordinary items, which eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary. However, this will not result in a loss of information as the presentation and disclosure guidance for items that are unusual in nature or occur infrequently will be retained. ASU 2015-01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015; early application is permitted. The provisions of this accounting update are not expected to have a material impact on the Company's financial position or results of operations.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15: Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. (ASU 2014-15). ASU 2014-15 asserts that management should evaluate whether there are relevant condition or events that are known and reasonably knowable that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date the financial statements are issued or are available to be issued when applicable. If conditions or events at the date the financial statements are issued raise substantial doubt about an entity's ability to continue as a going concern, disclosures are required which will enable users of the financial statements to understand the conditions or events as well as management's evaluation and plan. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual and interim periods thereafter; early application is permitted. The provisions of this accounting update are not expected to have a material impact on the Company's financial position or results of operations.

In May 2014, the FASB and the International Accounting Standards Board jointly issued new accounting guidance for recognition of revenue Accounting Standards Update No. 2014-09: Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). This new guidance replaces virtually all existing U.S. GAAP and International Financial

Reporting Standards guidance on revenue recognition. ASU 2014-09 is effective for fiscal years beginning after December 15, 2017. This new guidance applies to all periods presented. Early adoption is not allowed under U.S. GAAP. The new guidance requires companies to make more estimates and use more judgment than under current accounting guidance. The Company does not anticipate that the implementation of this new guidance will have a material impact on the Company’s consolidated financial position or results of operations for the periods presented.

3. Fair Value Measurements

Pursuant to Accounting Standards Codification 820, Fair Value Measurements and Disclosures (ASC 820), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following table sets forth, by level within the fair value hierarchy, the Company’s financial assets and liabilities that were accounted for at fair value as of June 30, 2015. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have been no transfers between Level 1, Level 2 or Level 3.

Fair value information for financial assets and liabilities was as follows as of June 30, 2015 (in thousands):

	Total Carrying Value	Fair Value Measurements Using Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$ 3	$ —	$ 3	$ —
Commodity price contracts - liabilities	$ (13)	$ —	$ (13)	$ —

Derivatives listed above include collars that are carried at fair value. The Company records the net change in the fair value of these positions in "Loss on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. As of December 31, 2014, there were no outstanding commodity price contracts. See Note 4 - "Derivative Instruments" for additional discussion of derivatives.

As of June 30, 2015, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Estimates of the fair value of financial instruments are made in accordance with the requirements of ASC 825, Financial Instruments. The estimated fair value amounts are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's credit facility with the Royal Bank of Canada and other lenders (the “RBC Credit Facility”) approximates carrying value because the facility interest rate approximates current market rates and is re-set at least every three months. See Note 8 - "Long-Term Debt" for further information.

4. Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are typically utilized to hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company typically hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. The Company believes that these derivative arrangements, although not free of risk, allow it to achieve a more predictable cash flow and to reduce exposure to commodity price fluctuations. However, derivative arrangements limit the benefit of increases in the prices of crude oil, natural gas and natural gas liquids sales. Moreover, because its derivative arrangements apply only to a portion of its production, the Company’s strategy provides only partial protection against declines in commodity prices. Such arrangements may expose the Company to risk of financial loss in certain circumstances. The Company continuously reevaluates its hedging programs in light of changes in production, market conditions and commodity price forecasts.

As of June 30, 2015, the Company’s crude oil derivative positions consisted of costless put/call “collars.” A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract, and a purchased put that establishes a minimum price.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The Company does not post collateral, nor is exposed to potential margin calls, under any of these contracts as they are secured under the RBC Credit Facility. See Note 8 - "Long-Term Debt" for further information regarding the RBC Credit Facility.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in "Loss on derivatives, net" on the consolidated statements of operations.

The following derivative contracts were in place at June 30, 2015 (fair value in thousands):

Commodity	Period	Derivative	Volume/Month	Price/Unit (1)	Fair Value
Crude Oil	Jul 2015	Collar	25,000 Bbls	$55.00 - $65.05	$ 3
Crude Oil	Jul 2015 - Dec 2015	Collar	35,000 Bbls	$55.00 - $65.15	(13)
		Total net fair value of derivative instruments			$ (10)

(1) Commodity derivatives based on NYMEX West Texas Intermediate crude oil prices.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of June 30, 2015 (in thousands):

	Gross	Netting (1)	Total
Assets	$ 3	$ (3)	$ —
Liabilities	$ (13)	$ 3	$ (10)

(1) Represents counterparty netting under agreements governing such derivatives.
As of December 31, 2014, the Company did not have any outstanding derivative positions.

The following table summarizes the effect of derivative contracts on the Consolidated Statements of Operations for the three and six months ended June 30, 2015 and 2014 (in thousands):

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Crude oil contracts	$ —	$ (809)	$ —	$ (1,171)
Natural gas contracts	—	(242)	—	(1,582)
Realized loss	$ —	$ (1,051)	$ —	$ (2,753)
Crude oil contracts	$ (10)	$ (394)	$ (10)	$ (235)
Natural gas contracts	—	182	—	(234)
Unrealized loss	$ (10)	$ (212)	$ (10)	$ (469)
Loss on derivatives, net	$ (10)	$ (1,263)	$ (10)	$ (3,222)

5. Stock-Based Compensation

During the six months ended June 30, 2015, the Company had a stock-based compensation program which allows for stock options and/or restricted stock to be awarded to officers, directors, consultants and employees. This program includes (i) the Company's Amended and Restated 2009 Incentive Compensation Plan (the “2009 Plan”); and (ii) the Crimson 2005 Stock Incentive Plan (the “2005 Plan” or "Crimson Plan") adopted in conjunction with the merger with Crimson Exploration Inc. in October 2013 (the “Merger”), which expired on February 25, 2015.

Stock Options

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the six months ended June 30, 2015 and 2014, there was no excess tax benefit recognized.

Compensation expense related to stock option grants are recognized over the stock option’s vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. No stock options were granted during the six months ended June 30, 2015 or 2014.

During the six months ended June 30, 2015, no stock options were exercised and stock options for 587 shares of common stock were forfeited by former employees. During the six months ended June 30, 2014, 4,081 stock options were exercised and stock options for 387 shares of common stock were forfeited.

Restricted Stock

During the six months ended June 30, 2015, the Company granted 270,091 shares of restricted common stock under the 2009 Plan. Of these, 242,887 shares were granted to employees as part of their overall compensation package, which vest over four years, and 27,204 shares were granted to directors pursuant to the Company's director compensation plan, which vest after one year. Additionally, the Company issued the final 7,030 shares of restricted stock under the 2005 Plan to employees as part of their compensation package, which vest over four years. The weighted average fair value of the restricted shares granted during the six months ended June 30, 2015, was $22.02 with a total fair value of approximately $6.1 million after adjustment for an estimated weighted average forfeiture rate of 4.9%. Approximately 0.9 million shares remain available for grant under the 2009 Plan as of June 30, 2015.

During the six months ended June 30, 2015, 4,519 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the six months ended June 30, 2015 was approximately $142 thousand.

During the six months ended June 30, 2015, the Company recognized approximately $2.6 million in stock-based compensation expense for the vesting of restricted shares previously granted to its officers, employees and directors. As of June 30, 2015, an additional $10.7 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 2.6 years.

6. Other Financial Information

The following table provides additional detail for accounts receivable, prepaid expenses and other, and accounts payable and accrued liabilities which are presented on the Consolidated Balance Sheets (in thousands):

	June 30, 2015	December 31, 2014
Accounts receivable:		
Trade receivable	$ 12,228	$ 13,926
Receivable for Alta Resources distribution	1,993	1,993
Joint interest billing	4,919	4,096
Income taxes receivable	3,236	3,274
Other receivables	1,461	2,610
Allowance for doubtful accounts	(666)	(590)
Total accounts receivable	$ 23,171	$ 25,309
Prepaid expenses and other:		
Prepaid insurance	$ 2,355	$ 1,242
Other	760	699
Total prepaid expenses and other	$ 3,115	$ 1,941

Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 23,678	$ 31,653
Accrued exploration and development	13,473	26,538
Trade payables	8,034	17,282
Advances from partners	2,871	8,334
Accrued general and administrative expenses	5,069	6,258
Termination fees (1)	2,456	—
Other accounts payable and accrued liabilities	4,466	2,827
Total accounts payable and accrued liabilities	$ 60,047	$ 92,892

(1) Accrued fee related to early termination of drilling rig contract.

Included in the table below is supplemental information about certain cash and non-cash transactions during the six months ended June 30, 2015 and 2014 (in thousands):

	Six Months Ended June 30,	
	2015	2014
Cash payments:		
Interest payments	1,503	1,531
Income tax payments	34	132
Non-cash investing activities in the consolidated statements of cash flows:		
Increase (decrease) in accrued capital expenditures	(13,065)	7,996

7. Investment in Exaro Energy III LLC

In April 2012, the Company entered into a Limited Liability Company Agreement (the "LLC Agreement") in connection with the formation of Exaro. Pursuant to the LLC Agreement, as amended, the Company committed to invest up to $67.5 million in Exaro for an ownership interest of approximately 37%. As of December 31, 2014, the Company had invested approximately $46.9 million. No additional contributions were made during the six months ended June 30, 2015.

The following table (in thousands) presents condensed balance sheet data for Exaro as of June 30, 2015 and December 31, 2014. The balance sheet data was derived from the Exaro balance sheet as of June 30, 2015 and December 31, 2014 and was not adjusted to represent the Company's percentage of ownership interest in Exaro. The Company's share in the equity of Exaro at June 30, 2015 was approximately $60.9 million.

	June 30, 2015	December 31, 2014
Current assets	$ 30,453	$ 35,013
Non-current assets:		
Net property and equipment	232,143	233,997
Restricted cash escrow account	—	577
Other non-current assets	623	1,779

Total non-current assets	232,766	236,353
Total assets	$ 263,219	$ 271,366
Current liabilities	$ 6,273	$ 9,405
Non-current liabilities:		
Long-term debt	89,500	94,500
Other non-current liabilities	1,850	1,084
Total non-current liabilities	91,350	95,584
Members' equity	165,596	166,377
Total liabilities & members' equity	$ 263,219	$ 271,366

13

The following table (in thousands) presents the condensed results of operations for Exaro for the three and six months ended June 30, 2015 and 2014. The results of operations for the three and six months ended June 30, 2015 and 2014 were derived from Exaro's financial statements for the respective periods. The income statement data below was not adjusted to represent the Company's ownership interest but rather reflects the results of Exaro as a company. The Company's share in Exaro's results of operations recognized for the three months ended June 30, 2015 and 2014 was a loss of $0.7 million, net of tax benefit of $0.4 million, and a gain of $1.5 million, net of tax expense of $0.8 million, respectively. The Company's share of Exaro's results of operations recognized for the six months ended June 30, 2015 and 2014 was a loss of $0.2 million, net of tax benefit of $0.1 million, and a gain of $3.1 million, net of tax expense of $1.7 million, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Production:				
Oil (thousand barrels)	45	42	87	83
Gas (million cubic feet)	3,361	3,314	6,692	6,453
Total (million cubic feet equivalent)	3,634	3,565	7,214	6,949
Oil and natural gas sales	$ 10,572	$ 19,951	$ 23,850	$ 42,290
Other loss	(2,095)	(17)	(59)	(1,992)
Less:				
Lease operating expenses	4,203	5,180	8,479	11,412
Depreciation, depletion, amortization & accretion	6,294	6,457	12,918	12,126
General & administrative expense	1,138	1,091	1,862	1,950
Income (loss) from continuing operations	(3,158)	7,206	532	14,810
Net interest expense	(679)	(1,048)	(1,554)	(1,966)
Net income (loss)	$ (3,837)	$ 6,158	$ (1,022)	$ 12,844

Included in Other loss are realized and unrealized gains and losses attributable to derivatives, whose value is likely to change based on future oil and gas prices. Exaro's results of operations do not include income taxes because Exaro is treated as a partnership for tax purposes.

8. Long-Term Debt

RBC Credit Facility

In October 2013, the Company entered into a $500 million four-year revolving credit facility with Royal Bank of Canada and other lenders with an initial hydrocarbon supported borrowing base of $275 million. Effective May 7, 2015, as part of the regular redetermination schedule, the Company's bank group redetermined the Company's borrowing base at $225 million, primarily due to lower commodity prices. The next regular scheduled redetermination will be November 1, 2015.

As of June 30, 2015 and December 31, 2014, the Company had approximately $111.4 million and $63.4 million, respectively, outstanding under the RBC Credit Facility and $1.9 million and $1.9 million, respectively, in outstanding letters of credit. As of June 30, 2015, borrowing availability under the RBC Credit Facility was $111.7 million.

Borrowings under the RBC Credit Facility bear interest at a rate that is dependent upon LIBOR, the U.S. prime rate, or the federal funds rate, plus a margin dependent upon the amount outstanding. Additionally, the Company must pay a commitment fee on the amount of the facility that remains unused, which varies from .375% to .5%, depending on the amount of the credit facility that is unused. Total interest expense under the RBC Credit Facility, including commitment fees, for the three and six months ended June 30, 2015 was approximately $0.8 million and $1.5 million, respectively. Total interest expense under the RBC Credit Facility, including commitment fees, for the three and six months ended June 30, 2014 was approximately $0.7 million and $1.4 million, respectively.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require the maintenance of a minimum current ratio and a maximum leverage ratio. As of June 30, 2015, the Company was in compliance with all covenants under the RBC Credit Facility. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at June 30, 2015 and December 31, 2014 was 2.04% and 1.96%, respectively. The RBC Credit Facility matures on October 1, 2017, at which time any outstanding balances will be due.

9. Income Taxes

The Company’s income tax provision for continuing operations consists of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Current tax provision (benefit):				
Federal	$ —	$ —	$ —	$ (524)
State	315	122	522	713
Total	$ 315	$ 122	$ 522	$ 189
Deferred tax provision (benefit):				
Federal	$ (10,451)	$ 1,378	$ (20,623)	$ (6,426)
State	(250)	(493)	(534)	(475)
Total	$ (10,701)	$ 885	$ (21,157)	$ (6,901)
Total tax provision (benefit):				
Federal	$ (10,451)	$ 1,378	$ (20,623)	$ (6,950)
State	65	(371)	(12)	238
Total	$ (10,386)	$ 1,007	$ (20,635)	$ (6,712)
Included in gain (loss) from investment in affiliates	$ (400)	$ 795	$ (100)	$ 1,669
Total income tax provision (benefit)	$ (9,986)	$ 212	$ (20,535)	$ (8,381)

10. Related Party Transactions

Juneau Exploration L.P.

In April 2012, Mr. Brad Juneau, the sole manager of the general partner of Juneau Exploration L.P. (“JEX”), joined the Company’s Board of Directors. On January 1, 2013, the Company, entered into an advisory agreement with JEX (the "Contaro Advisory Agreement"). Under the Contaro Advisory Agreement, JEX provided advisory services to Contaro in connection with Contaro's investment in Exaro, and Mr. Juneau served on the Board of Managers of Exaro and performed such duties as described in the limited liability company operating agreement of Exaro. Pursuant to the Contaro Advisory Agreement, JEX was paid a monthly fee of $10,000 and was entitled to receive a 1% fee of the cash profit earned by Contaro.

On March 19, 2014, Mr. Juneau resigned from the Company’s board of directors and no longer provides services under the Contaro Advisory Agreement. As a result, the Contaro Advisory Agreement was terminated effective as of March 19, 2014.

Olympic Energy Partners

In December 2012, Mr. Joseph J. Romano was elected President and Chief Executive Officer of the Company and in April 2013 was named Chairman of the Company. Upon the Merger with Crimson Exploration Inc. (“Crimson”) on October 1, 2013, Mr. Romano resigned as President and Chief Executive Officer, but remains Chairman. Mr. Romano is also the President and Chief Executive Officer of Olympic Energy Partners LLC ("Olympic").

JEX, affiliates of JEX, and Olympic 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 its ownership in Company-operated wells is limited to its 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 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 June 30, 2015, Olympic, JEX, REX and JEX employees owned the following interests in the Company's offshore wells.

	Olympic		JEX		REX		JEX Employees
	WI	NRI	WI	NRI	WI	NRI	ORRI
Dutch #1 - #5	3.53%	2.84%	1.88%	1.51%	—%	—%	2.02%
Mary Rose #1	3.61%	2.70%	2.01%	1.51%	—%	—%	2.79%
Mary Rose #2 - #3	3.61%	2.58%	2.01%	1.44%	—%	—%	2.79%
Mary Rose #4	2.34%	1.70%	1.31%	0.95%	—%	—%	1.82%
Mary Rose #5	2.56%	1.87%	1.43%	1.04%	—%	—%	1.82%
Ship Shoal 263	—%	—%	—%	—%	—%	—%	3.33%
Vermilion 170	—%	—%	4.30%	3.35%	12.50%	9.74%	3.33%

During the three and six months ended June 30, 2015, Mr. Romano earned $26 thousand and $53 thousand, respectively, for his service as a director of the Company. During the three and six months ended June 30, 2014, Mr. Romano earned $26 thousand and $52 thousand, respectively, for his service as a director of the Company. During the three months ended March 31, 2014, Mr. Juneau earned $12 thousand, for his service as a director of the Company, and on March 19, 2014, Mr. Juneau resigned from the board of directors.

During the quarter ended December 31, 2013, Mr. Romano and Mr. Juneau each received 1,622 shares of restricted stock, which vest 100% on the one-year anniversary of the date of grant, as part of their board of director compensation. In April 2014, the board of directors accelerated the vesting of Mr. Juneau's 1,622 shares which would have otherwise been forfeited upon his resignation in March 2014. The Company recognized compensation expense of approximately $71 thousand related to the shares granted to Mr. Juneau for the three months ended March 31, 2014. Additionally, during the quarters ended September 30, 2014 and June 30, 2015, the Company granted 2,612 and 4,534 shares of restricted stock, respectively, which both vest 100% on the one-year anniversary of the date of grant, to Mr. Romano as part of his board of director compensation. The Company recognized compensation expense of approximately $35 thousand and $62 thousand related to the shares granted to Mr. Romano for the three and six months ended June 30, 2015, respectively. During the three and six months ended June 30, 2014, the Company recognized compensation expense of approximately $18 thousand and $36 thousand, respectively, related to the shares granted to Mr. Romano.

In July 2014, Mr. Romano received a bonus of $4.0 million as a result of the Merger with Crimson. Approximately $1.3 million and $2.6 million related to this bonus is included in general and administrative expenses for the three and six months ended June 30, 2014, respectively.

Effective January 1, 2014, the Company subleased to JEX a portion of its previous office space at 3700 Buffalo Speedway, Houston, Texas for approximately $0.1 million per year, which approximates the Company's rental liability for that space. The sublease agreement expires in February 2016.

Below is a summary of payments received from (paid to) Olympic, JEX and REX in the ordinary course of business in the Company's 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):

	Three Months Ended June 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$ (875)	$ (571)	$ (242)	$ (2,265)	$ (1,501)	$ (672)
Joint interest billing receipts	195	172	25	212	132	111

	Six Months Ended June 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$ (2,141)	$ (1,359)	$ (495)	$ (4,212)	$ (2,812)	$ (1,346)
Joint interest billing receipts	289	227	68	282	157	156

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 June 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$ —	$ —	$ —	$ (54)	$ (29)	$ —
Rent received for sublease	—	—	—	—	43	—

	Six Months Ended June 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$ —	$ —	$ —	$ (54)	$ (29)	$ —
Rent received for sublease	—	119	—	—	66	—

As of June 30, 2015 and December 31, 2014, the Company's consolidated balance sheets reflected the following balances (in thousands):

	June 30, 2015			December 31, 2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Accounts receivable:						
Joint interest billing	$ 79	$ 53	$ 85	$ 48	$ 42	$ 12
Accounts payable:						
Royalties and revenue payable	(689)	(431)	(145)	(1,006)	(620)	(175)

Oaktree Capital Management L.P.

As of June 30, 2015, Oaktree Capital Management L.P. ("Oaktree"), through various funds, owned approximately 6.6% of the Company's stock. On October 1, 2013, Mr. James Ford, a Managing Director and Portfolio Manager within Oaktree, was elected to the Company's board of directors.

As part of Mr. Ford's director compensation, all cash and equity awards payable to Mr. Ford are instead granted to an affiliate of Oaktree. An affiliate of Oaktree received 1,622 shares of restricted stock during the quarter ended December 31, 2013, 2,612 shares of restricted stock during the quarter ended September 30, 2014, and 4,534 shares of restricted stock during the quarter ended June 30, 2015. These shares vest 100% on the one-year anniversary of the date of the grant.

During the three and six months ended June 30, 2015, the affiliate of Oaktree earned $15 thousand and $32 thousand in cash as a result of Mr. Ford's board participation, and the Company recognized compensation expense of approximately $35 thousand and $62 thousand related to the shares of restricted stock previously granted to an affiliate of Oaktree under the Director Compensation Plan. During the three and six months ended June 30, 2014, the affiliate of Oaktree earned $13 thousand and $32 thousand in cash as a result of Mr. Ford's board participation, and the Company recognized compensation expense of approximately $18 thousand and $36 thousand related to the shares of restricted stock previously granted to an affiliate of Oaktree under the Director Compensation Plan.

11. Commitments and Contingencies

Legal Proceedings

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

Mineral interest owners in South Louisiana filed suit against a subsidiary of the Company and several co-defendants in June 2009 in the 31st Judicial District Court situated in Jefferson Davis Parish, Louisiana alleging failure to act as a reasonably prudent operator, failure to explore, waste, breach of contract, etc. in connection with two wells located in Jefferson Davis Parish. Many of the alleged improprieties occurred prior to the Company’s ownership of an interest in the wells at issue, although the Company may have assumed liability otherwise attributable to its predecessors-in-interest through the acquisition documents relating to the acquisition of the Company's interest in these wells. The Company and its co-defendants obtained a favorable judgment from the trial court following a bench trial. In late 2014, the Louisiana Third Circuit Court of Appeals issued an opinion reversing the trial court's rulings and rendering judgment in favor of the plaintiffs for approximately $13.4 million. The decision by the court of appeals did not allocate liability among the defendants although the Company would likely be responsible for at least one-half, and possibly as much as two-thirds, of the judgment if it stands. The Company and its co-defendants filed an application for a writ of certiorari to the Louisiana Supreme Court seeking review of this case by the state's highest court. Our writ was granted in April 2015, although there remains uncertainty whether the Louisiana Supreme Court will rule in its favor. The Company and its co-defendants are vigorously defending this lawsuit and believe that they have a meritorious position. A companion case involving the same set of facts was filed in the same trial court on April 19, 2013 on behalf of additional mineral interest owners but has been inactive pending the appeal of the original case. The Company's potential exposure in this companion case is expected to be affected by the outcome of the Company's appeal of the original case.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by us or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company is vigorously defending this lawsuit, believes that it has meritorious defenses and is appealing the trial court's decision to the applicable state Court of Appeals.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The Company is vigorously defending this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

In February 2011, a subsidiary of the Company and certain of its working interest partners and insurance carriers brought suit against a marine construction, dredging and tunneling company and an instrumentality of the United States of America in the U.S. District Court for the Southern District of Texas – Houston Division seeking monetary damages for damage to an offshore pipeline which was struck by a dredge. Following a bench trial in December 2013, the Company and its co-plaintiffs obtained a favorable judgment from the trial court. The U.S. Court of Appeals for the 5th Circuit affirmed the trial court's ruling in May 2015, and in July 2015, one of the co-defendants paid the full amount of the $13.9 million judgment (approximately $4.8 million net to the Company).

In May 2015, a subsidiary of the Company and several working interest partners settled a lawsuit with a mineral interest owner and a third-party operator pending in district court for Dimmit County, Texas. The suit involved a challenge from the mineral interest owner to the validity of an oil and gas lease and various other claims relating to the property subject to the lease. The settlement resulted in the subsidiary of the Company and its working interest partners receiving $5.0 million ($2.5 million net to the Company) in exchange for a release of their respective interests in the lease at issue.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

Available Information

General information about us can be found on our website at www.contango.com. Our Annual Report 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"). We are not including the information on our website as a part of, or incorporating it by reference into, this Report.

Cautionary Statement about Forward-Looking Statements

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases "should be", "will be", "believe", "expect", "anticipate", "estimate", "forecast", "goal" and similar expressions ide forward-looking statements and express our expectations about future events. Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties that could cause or contribute to such differences include, without limitation, those discussed in the section entitled "Risk Factors" included in our Annual Report on Form 10-K and those factors summarized below:

- our financial position;
- our business strategy, including outsourcing;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- 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 natural gas processing facilities;
- the risks associated with acting as the operator in drilling deep high pressure and temperature wells, 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 we have made a large capital commitment relative to the size of our 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 and cost of rigs and other materials and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures, and other risks;
- 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;
- 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 legislative and regulatory developments and approvals;
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements; and
- ability to obtain insurance coverage on commercially reasonable terms.

Any of these factors and other factors described in this report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable when made, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. All forward-looking statements speak only as of the date of this report.

We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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.

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 Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2014 (our "2014 Form 10-K"), previously filed with the Securities and Exchange Commission ("SEC").

Overview

We are a Houston, Texas based, independent oil and natural gas company. Our business is to maximize production and cash flow from our onshore properties in various plays and offshore properties in the shallow waters of the Gulf of Mexico ("GOM"), and to use that cash flow to explore, develop, exploit and acquire crude oil and natural gas properties in the onshore Texas Gulf Coast and Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of June 30, 2015:

Location	Formation
Gulf of Mexico	Offshore Louisiana – water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Zavala and Dimmitt counties, Texas	Buda / Austin Chalk
Weston County, Wyoming	Muddy Sandstone
Texas Gulf Coast	Conventional formations
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC ("Exaro"). Production from this entity is not included in our production results for the three or six months ended June 30, 2015 or in its reported reserves as of December 31, 2014. See "Other Investments" below for more information.

We intend to grow reserves and production by further exploiting the unproved resource potential on our existing onshore property base with specific activity in any particular area or time, to be a function of drilling success, commodity prices and/or prevailing service costs. In addition, we own developed and undeveloped acreage in several regions that we believe provides additional unproved resource potential that could provide significant long-term growth in production and reserves.

Due to the current challenging commodity price environment, we are focusing our 2015 capital program on: (i) the preservation of our strong and flexible financial position, including limiting our overall capital expenditure budget; (ii) dedicating capital primarily to de-risking and/or delineating strategic projects (i.e. versus field development); (iii) the identification of opportunities for cost and production efficiencies in all areas of our operations; and (iv) continuing to identify and, when appropriate, pursue the expansion of our resource potential through opportunistic acquisitions. No drilling activity is planned for the GOM in 2015.

The following table lists the areas to which we have budgeted to allocate capital during 2015:

Location	Formation
Madison and Grimes counties, Texas	Woodbine (Upper and Lower Lewisville)
Weston County, Wyoming	Muddy Sandstone
Fayette and Gonzales counties, Texas	Navarro / Buda / Austin Chalk

Activity within each location listed above is described in more detail below.

Gulf of Mexico

On April 29, 2014, we reached total depth on our Ship Shoal 255 well, and no commercial hydrocarbons were found. As a result, for the three months ended June 30, 2014, we recognized $10.1 million in exploration expense for the cost of drilling the well and $0.5 million in impairment expense for the associated platform located in Block Ship Shoal 263. For the six months ended June 30, 2014, we recognized total of $36.8 million in exploration expense for the cost of drilling the well and $15.6 million in impairment expense, including $3.5 million related to leasehold costs and $12.1 million related to the platform located at Block Ship Shoal 263, which was expected to be used by the Ship Shoal 255 well, had it been successful.

We currently hold six untested exploratory prospects and 15 offshore lease blocks. We recognized full impairment related to the prospects in the fourth quarter of 2014 as we are not likely to drill these prospects prior to expiration.

Madison and Grimes Counties, Texas

During the quarter ended June 30, 2015, we brought five gross wells (3.1 net) on production, including four of which were drilled utilizing a pad drilling strategy on 500 foot spacing in the Chalktown area. When drilling from pads, several wells are drilled in succession, completed in succession, and then all placed on production simultaneously. As of June 30, 2015 we had seven pad-drilled wells on production. As of June 30, 2015, the initial three wells combined were averaging approximately 1,400 Boepd (760 Boepd net to Contango) after five and half months of production, while the remaining four wells combined were averaging 1,400 Boepd (650 Boepd net to Contango) after approximately two months of production. We are pleased with the production from the individual well results drilled on 500 foot spacing; however, in this commodity price environment, we do not believe that the 500 foot spacing strategy provides the optimum return on invested capital. Future drilling in this area will likely be planned on at least 1,000 foot spacing. As of June 30, 2015, we had 37 gross wells (24.0 net) producing in the Woodbine formation, consisting of 20 gross wells (12.9 net) in the Force area, five gross wells (3.2 net) in the Iola/Grimes area and 12 gross wells (7.9 net) in the Chalktown area.

We recently drilled the Hoke #1 well as a vertical pilot well in the Chalktown Area of our Madison and Grimes County acreage with 250 feet of whole core recovered for enhanced reservoir analysis. The primary zone of interest is the Lower Lewisville Sand which is approximately 130 feet thick and has not been completed in any vertical or horizontal wells at this time. Early log indications are encouraging, and we are currently awaiting the final core analysis of this zone prior to commencing any drilling for this potentially significant objective.

We recently drilled the Norwood 2H well as an Upper Lewisville test in Grimes County, Texas to assess the concept of using longer laterals, more fracs stages and more proppant in completing a well, but results were disappointing. This is our third test of the Upper Lewisville formation in Grimes County, with the combined results, on average, failing to provide economics sufficient enough to continue to pursue the Upper Lewisville in this area. We previously drilled the Stokes #1 vertical pilot well in Grimes County and took whole cores for purposes of analyzing the viability of the Eagle Ford in the area. The core analysis indicates that the rock properties of the Eagle Ford here are not dissimilar to those present in the East Texas Eagle Ford play currently being developed in Brazos and Burleson counties, Texas; therefore, we still believe there is potential for the Eagle Ford, Lower Lewisville and Middle Lewisville in Grimes County that could be tested in an improved commodity price environment.

Within the past year, we have taken several whole core samples of nearby zones and are encouraged by their log results. Once commodity prices improve and/or service costs decline, we may increase our activity in this area. We have a multi-year inventory of potential drilling locations, including the Woodbine, Eagle Ford Shale, Buda and other formations.

Zavala and Dimmit Counties, Texas

In late 2014 we drilled a vertical pilot well to test the viability of the Eagle Ford and other formations over our South Texas acreage. We have been encouraged by the preliminary core analysis and will likely plan a test well targeting the Eagle Ford for 2016 on our KM Ranch acreage in Zavala County utilizing longer laterals, more frac stages and more proppant than used in our two previous Eagle Ford wells in this area. Operators continue to drill wells with excellent productivity in the immediate area of our leasehold.

Weston County, Wyoming

In June 2015, we announced the discovery and successful completion of the Elliot #1H well (80% WI) in the Muddy Sandstone formation in Weston County, Wyoming (referred to as our North Cheyenne Project). We have approximately 49,000 gross acres (35,000 net) in this area. We anticipate spudding one to two additional wells beginning in late summer 2015 to further delineate this discovery with full scale development possibly beginning in early 2016 with one to two rigs. Approximately 200 to 300 Muddy horizontal well locations may be prospective on the acreage based on a drilling density of three to four wells per 640 acres. Additional prospective horizons in this area will be evaluated during the delineation phase with additional log and core data and could also add significantly to the total number of potential horizontal locations.

Natrona County, Wyoming

During the fourth quarter of 2014, we drilled the State #1H well in the Mowry Shale formation in Natrona County, Wyoming (referred to as our FRAMS Project). In April 2015, initial flowback began and no hydrocarbons were produced during the testing period. As a result, for the three months ended June 30, 2015, we recognized $6.5 million in exploration expenses for the cost of drilling the well. Though this well was disappointing, we did earn approximately 23,000 net acres in the prospect area under this drill-to-earn arrangement and will continue to evaluate the possibility of testing other formations on the acreage earned.

Fayette and Gonzales Counties, Texas

In 2014, we acquired approximately 25,000 net acres primarily in Fayette and Gonzales counties, Texas (referred to as our Elm Hill Project), to pursue horizontal drilling in this multiple formation play. As of June 30, 2015, we had completed three gross (1.5 net) wells in various formations on this acreage, with two additional wells in the completion stage which are expected to begin production early in the third quarter of 2015. We have recovered four whole cores to further evaluate six hydrocarbon bearing formations that we believe have potential for development. We and our partners will monitor production and formation results before determining future plans for this area.

Summary Production Information

Our production for the three months ended June 30, 2015 was approximately 60% offshore and 40% onshore, and 64% natural gas, 18% oil and 18% natural gas liquids. Our production for the three months ended June 30, 2014 was 59% offshore and 41% onshore, and approximately 64% natural gas, 22% oil and 14% natural gas liquids.

The table below sets forth our average net daily production data in Mmcfed for each of our various operating regions for each of the periods indicated:

	Three Months Ended					
	June 30, 2014	September 30, 2014		December 31, 2014	March 31, 2015	June 30, 2015
Offshore GOM						
Dutch and Mary Rose	60.9	42.3	(5)	55.9	53.3	50.8
Vermilion 170	7.2	8.0		5.7	7.7	6.3
Other offshore (1)	0.6	5.2		6.5	3.2	1.6
Southeast Texas (2)	27.1	26.6		23.6	19.3	28.2
South Texas (3)	16.0	17.4		12.2	10.8	9.3
Other (4)	4.2	2.8		2.3	2.0	2.2
	116.0	102.3		106.2	96.3	98.4

(1) Includes Ship Shoal 263 and South Timbalier 17.
(2) Includes Madison and Grimes counties, among others.
(3) Includes Zavala and Dimmit counties, among others.
(4) Includes onshore wells in East Texas, Rocky Mountain and Tuscaloosa Marine Shale regions, among others.
(5) Decrease mainly attributable to shut-in for approximately three weeks to install compression.

Other Investments

Kaybob Duvernay - Alberta, Canada

On August 1, 2013, our wholly-owned subsidiary, Alta Resources Investments, LLC (“Alta”) sold its interest in the liquids-rich Kaybob Duvernay Play in Alberta, Canada for approximately $30.5 million net to us. Of this amount, we have received $28.5 million, and expect to receive the remaining $2.0 million once approved by regulatory officials.

Jonah Field - Sublette County, Wyoming

Our wholly-owned subsidiary, Contaro Company (“Contaro”) currently has a 37% ownership interest in Exaro and has committed to invest up to $67.5 million in cash in Exaro. As of June 30, 2015, Contaro had invested approximately $46.9 million in Exaro.

As of June 30, 2015, Exaro had 645 wells on production over its 5,760 gross acres (1,040 net), with a working interest between 14.4% and 32.5%. These wells were producing at a rate of approximately 40 Mmcfed, net to Exaro, plus an additional three wells that are either in the completion or fracture stimulation phase. The operator expects to have one to two drilling rigs running on this project during the remainder of 2015. For the quarter ended June 30, 2015, we recognized a net investment loss of approximately $0.7 million, net of tax benefit of $0.4 million, as a result of our investment in Exaro. For the quarter ended June

30, 2014, we recognized a net investment gain of approximately $1.5 million, net of tax expense of $0.8 million. For the six months ended June 30, 2015, we recognized a net investment loss of approximately $0.2 million, net of tax benefit of $0.1 million, as a result of our investment in Exaro. For the six months ended June 30, 2014, we recognized a net investment gain of approximately $3.1 million, net of tax expense of $1.7 million. We do not anticipate making any additional equity contributions during 2015 as Exaro estimates drilling capital will be funded through internally generated cash flow and borrowings under its revolving credit facility. See Note 7 to our Financial Statements - "Investment in Exaro Energy III LLC" for additional details related to this investment.

Other

We intend to continue to evaluate potential acquisition opportunities to expand our presence in resource plays, to exploit our oil and liquids-rich positions and to continue to develop exploration and exploitation opportunities where commodity price-justified. Acquisition efforts will typically be focused on areas in which we can leverage our geographic and geological expertise to exploit identified drilling opportunities and where we can develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves.

Results of Operations for the Three and Six Months Ended June 30, 2015 and 2014

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the three and six months ended June 30, 2015 and 2014. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six thousand cubic feet ("Mcf") of natural gas. Reported lease operating expenses include production taxes, such as ad valorem and severance taxes.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2015	2014	%	2015	2014	%
Revenues:	(thousands except prices)			(thousands except prices)		
Oil and condensate sales	$ 15,688	$ 38,340	(59)%	$ 26,382	$ 73,440	(64)%
Natural gas sales	15,287	31,244	(51)%	32,110	65,871	(51)%
NGL sales	4,359	8,835	(51)%	7,489	19,365	(61)%
Total revenues	$ 35,334	$ 78,419	(55)%	$ 65,981	$ 158,676	(58)%
Production:						
Oil and condensate (thousand barrels)						
Offshore GOM	53	74	(28)%	107	155	(31)%
Southeast Texas	163	192	(15)%	290	378	(23)%
South Texas	43	91	(53)%	95	168	(43)%
Other	16	24	(33)%	25	37	(32)%
Total oil and condensate	275	381	(28)%	517	738	(30)%
Natural gas (million cubic feet)						
Offshore GOM	4,267	4,893	(13)%	8,927	10,263	(13)%
Southeast Texas	885	888	*	1,473	1,702	(13)%
South Texas	456	729	(37)%	965	1,247	(23)%

Other	103	220	(53)%	215	349	(38)%
Total natural gas	5,711	6,730	(15)%	11,580	13,561	(15)%
Natural gas liquids (thousand barrels)						
Offshore GOM	126	152	(17)%	259	318	(19)%
Southeast Texas	117	72	63 %	180	146	23 %
South Texas	22	31	(29)%	48	56	(14)%
Other	2	2	— %	3	5	(40)%
Total natural gas liquids	267	257	4 %	490	525	(7) %
Total (million cubic feet equivalent)						
Offshore GOM	5,342	6,250	(15)%	11,123	13,098	(15)%
Southeast Texas	2,563	2,468	4 %	4,296	4,846	(11)%
South Texas	849	1,456	(42)%	1,820	2,594	(30)%
Other	204	386	(47)%	384	598	(36)%
Total production	8,958	10,560	(15)%	17,623	21,136	(17)%

	Three Months Ended June 30, 2015	2014	%	Six Months Ended June 30, 2015	2014	%
Daily Production:	(thousands except prices)			(thousands except prices)		
Oil and condensate (thousand barrels per day)						
Offshore GOM	0.6	0.8	(28) %	0.6	0.9	(31) %
Southeast Texas	1.8	2.1	(15) %	1.6	2.1	(23) %
South Texas	0.5	1.0	(53) %	0.5	0.9	(43) %
Other	0.1	0.3	(33) %	0.2	0.2	(32) %
Total oil and condensate	3.0	4.2	(28) %	2.9	4.1	(30) %
Natural gas (million cubic feet per day)						
Offshore GOM	46.9	53.8	(13) %	49.3	56.7	(13) %
Southeast Texas	9.7	9.8	*	8.1	9.4	(13) %
South Texas	5.0	8.0	(37) %	5.3	6.9	(23) %
Other	1.2	2.4	(53) %	1.3	1.9	(38) %
Total natural gas	62.8	74.0	(15) %	64.0	74.9	(15) %
Natural gas liquids (thousand barrels per day)						
Offshore GOM	1.4	1.7	(17) %	1.4	1.8	(19) %
Southeast Texas	1.3	0.8	63 %	1.0	0.8	23 %
South Texas	0.2	0.3	(29) %	0.3	0.3	(14) %
Other	—	—	— %	—	—	(40) %
Total natural gas liquids	2.9	2.8	4 %	2.7	2.9	(7) %
Total (million cubic feet equivalent per day)						
Offshore GOM	58.7	68.7	(15) %	61.5	72.4	(15) %
Southeast Texas	28.2	27.1	4 %	23.7	26.8	(11) %
South Texas	9.3	16.0	(42) %	10.1	14.3	(30) %
Other	2.2	4.2	(47) %	2.1	3.3	(36) %
Total production	98.4	116.0	(15) %	97.4	116.8	(17) %
Average Sales Price:						
Oil and condensate (per barrel)	$ 57.14	$ 100.53	(43) %	$ 51.03	$ 99.52	(49) %
Natural gas (per thousand cubic feet)	$ 2.68	$ 4.64	(42) %	$ 2.77	$ 4.86	(43) %
Natural gas liquids (per barrel)	$ 16.33	$ 34.40	(53) %	$ 15.27	$ 36.91	(59) %
Total (per thousand cubic feet equivalent)	$ 3.94	$ 7.43	(47) %	$ 3.74	$ 7.51	(50) %
Expenses:						
Operating expenses	$ 10,972	$ 11,576	(5) %	$ 20,883	$ 22,629	(8) %
Exploration expenses	$ 6,924	$ 10,853	(36) %	$ 11,407	$ 37,784	(70) %
Depreciation, depletion and amortization	$ 38,770	$ 39,901	(3) %	$ 73,885	$ 74,303	(1) %
Impairment and abandonment of oil and gas properties	$ 236	$ 1,371	(83) %	$ 2,517	$ 16,566	(85) %
General and administrative expenses	$ 7,351	$ 9,207	(20) %	$ 15,179	$ 19,664	(23) %
Gain (loss) from investment in affiliates (net of taxes)	$ (745)	$ 1,478	(150)%	$ (187)	$ 3,100	(106)%
Selected data per Mcfe:						
Operating expenses	$ 1.22	$ 1.10	11 %	$ 1.18	$ 1.07	10 %
General and administrative expenses	$ 0.82	$ 0.87	(6) %	$ 0.86	$ 0.93	(8) %

Depreciation, depletion and amortization	$ 4.33	$ 3.78	15 %	$ 4.19	$ 3.52	19 %

* Less than 1%.

Three months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and from changes in commodity prices, which may fluctuate widely. Our production volumes are subject to wide swings as a result of new discoveries, weather events, transportation and processing constraints, and mechanical problems. In addition, our production naturally declines over time as we produce our reserves.

24

We reported revenues of $35.3 million for the three months ended June 30, 2015, compared to revenues of $78.4 million for the three months ended June 30, 2014. The decrease in revenues was primarily attributable to: (i) a significant drop in commodity prices, which contributed approximately $28.0 million of the decrease in revenues and (ii) approximately $15.1 million due to lower production volumes resulting from a commodity price related reduction in drilling.

Total equivalent production declined from 116.0 Mmcfed to 98.4 Mmcfed, a decrease attributable primarily to typical field decline (approximately 10.0 Mmcfed) in our Gulf of Mexico production and a 6.7 Mmcfed decline in South Texas production due to the strategic decrease in our capital program during 2015 due to the low, and uncertain, commodity price environment.

Average Sales Prices

The average equivalent sales price realized for the three months ended June 30, 2015 was $3.94 per Mcfe compared to $7.43 per Mcfe for the three months ended June 30, 2014. This decrease was attributable primarily to the decrease in the realized price of oil to $57.14 per barrel, compared to $100.53 per barrel for the three months ended June 30, 2014, and to the decrease in the realized price of natural gas to $2.68 per Mcf, compared to $4.64 per Mcf for the three months ended June 30, 2014.

Operating Expenses

Operating expenses for the three months ended June 30, 2015 were approximately $11.0 million, or $1.22 per Mcfe, compared to $11.6 million, or $1.10 per Mcfe, for the three months ended June 30, 2014. The table below provides additional detail of operating expenses for the three months ended June 30, 2015 and 2014:

	Three Months Ended June 30,			
	2015		2014	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 6,858	$ 0.77	$ 6,512	$ 0.62
Production & ad valorem taxes	1,794	0.20	3,134	0.30
Transportation & processing costs	1,242	0.13	1,576	0.15
Workover costs	1,078	0.12	354	0.03
Total operating expenses	$ 10,972	$ 1.22	$ 11,576	$ 1.10

Production and ad valorem taxes decreased by 43% for the three months ended June 30, 2015 compared to the three months ended June 30, 2014, due to the decrease in revenues for the same periods.

Exploration Expenses

Exploration expenses for the three months ended June 30, 2015 were approximately $6.9 million, which included $6.5 million in dry-hole costs related to our State #1H well. Exploration expenses for the three months ended June 30, 2014 were approximately $10.9 million, which included $10.1 million in dry-hole costs related to our Ship Shoal 255 well.

Impairment Expenses

Impairment expenses for the three months ended June 30, 2015 included a $0.3 million partial impairment of certain unproved prospects due to expiring leases. Impairment expense for the three months ended June 30, 2014 included a $0.5 million impairment of the platform that was expected to be used by the Ship Shoal 255 well.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended June 30, 2015 was approximately $38.8 million or $4.33 per Mcfe. This compares to approximately $39.9 million or $3.78 per Mcfe for the three months ended June 30, 2014. The higher depletion rate for 2015 resulted primarily from the negative revisions to proved, developed, producing reserves at the end of 2014.

General and Administrative Expenses

General and administrative expenses for the three months ended June 30, 2015 were approximately $7.4 million, compared to $9.2 million for the three months ended June 30, 2014. The prior year quarter included $1.3 million in merger related costs.

Gain from Affiliates

For the three months ended June 30, 2015, the Company recorded a loss from affiliates of approximately $0.7 million, net of tax benefit of $0.4 million, related to our investment in Exaro, compared to a gain of $1.5 million, net of tax expense of $0.8

million, for the three months ended June 30, 2014. The loss resulted from lower natural gas prices offsetting higher production from the Jonah Field.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and from changes in commodity prices, which may fluctuate widely. Our production volumes are subject to wide swings as a result of new discoveries, weather events, transportation and processing constraints, and mechanical problems. In addition, our production naturally declines over time as we produce our reserves.

We reported revenues of $66.0 million for the six months ended June 30, 2015, compared to revenues of $158.7 million for the six months ended June 30, 2014. The decrease in revenues was primarily attributable to: (i) a significant drop in commodity prices, which contributed approximately $59.8 million of the decrease in revenues and (ii) approximately $32.9 million due to lower production volumes resulting from a reduction in drilling due to the low-price environment.

Total equivalent production declined from 116.8 Mmcfed to 97.4 Mmcfed, a decrease attributable primarily to typical field decline (approximately 10.9 Mmcfed) in our Gulf of Mexico production and a 4.2 Mmcfed and 3.1 Mmcfed decline in South Texas and Southeast Texas production due to the strategic decrease in our capital program during 2015 due to the low, and uncertain, commodity price environment.

Average Sales Prices

The average equivalent sales price realized for the six months ended June 30, 2015 was $3.74 compared to $7.51 for the six months ended June 30, 2014. This decrease was attributable primarily to the decrease in the realized price of oil to $51.03 per barrel, compared to $99.52 per barrel for the six months ended June 30, 2014, and to the decrease in the realized price of natural gas to $2.77 per Mcf, compared to $4.86 per Mcf for the six months ended June 30, 2014.

Operating Expenses

Operating expenses for the six months ended June 30, 2015 were approximately $20.9 million, or $1.18 per Mcfe, compared to $22.6 million, or $1.07 per Mcfe, for the six months ended June 30, 2014. The table below provides additional detail of operating expenses for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30,			
	2015		2014	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 13,620	$ 0.76	$ 12,928	$ 0.61
Production & ad valorem taxes	2,937	0.17	6,063	0.29
Transportation & processing costs	2,621	0.15	2,714	0.13

Workover costs	1,705	0.10	924	0.04
Total operating expenses	$ 20,883	$ 1.18	$ 22,629	$ 1.07

Production and ad valorem taxes decreased by 52% for the six months ended June 30, 2015 compared to the six months ended June 30, 2014, due to the decrease in revenues for the same periods.

Exploration Expenses

Exploration expenses for the six months ended June 30, 2015 were approximately $11.4 million, which included $6.5 million in dry-hole costs related to our State #1H well and $3.2 million related to the early termination of a drilling rig contract. Exploration expenses for the six months ended June 30, 2014 were approximately $37.8 million, which included $36.8 million in dry-hole costs related to our Ship Shoal 255 well.

Impairment Expenses

Impairment expenses for the six months ended June 30, 2015 included producing property impairments of $2.0 million for small marginal natural gas properties as a result of commodity price declines. Impairment expenses for the six months ended June 30, 2015 also included a $0.5 million partial impairment of certain unproved prospects due to expiring leases. Impairment expense for the six months ended June 30, 2014 included a $3.5 million impairment of leasehold costs related to our Ship Shoal 255 block and $12.1 million impairment of the platform that was expected to be used by the Ship Shoal 255 well.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the six months ended June 30, 2015 was approximately $73.9 million or $4.19 per Mcfe. This compares to approximately $74.3 million or $3.52 per Mcfe for the six months ended June 30, 2014. The higher depletion rate for 2015 resulted primarily from the negative revisions to proved, developed, producing reserves at the end of 2014.

General and Administrative Expenses

General and administrative expenses for the six months ended June 30, 2015 were approximately $15.2 million, compared to $19.7 million for the six months ended June 30, 2014. The prior year six months ended included $2.6 million in merger related costs.

Gain from Affiliates

For the six months ended June 30, 2015, the Company recorded a loss from affiliates of approximately $0.2 million, net of tax benefit of $0.1 million, related to our investment in Exaro, compared to a gain of $3.1 million, net of tax expense of $1.7 million, for the six months ended June 30, 2014. The loss resulted from lower natural gas prices offsetting higher production from the Jonah Field.

Capital Resources and Liquidity

During the three months ended June 30, 2015, we incurred $11.9 million for capital projects, including $1.1 million on the Woodbine formation in our Madison and Grimes counties area, $1.4 million related to drilling on our Elm Hill Project in Fayette and Gonzales counties, $4.2 million in drilling costs on our FRAMS and North Cheyenne Projects in Wyoming and $4.5 million for the acquisition of leases and other rights in new areas.

During the six months ended June 30, 2015, we incurred $43.6 million for capital projects, including $15.2 million on the Woodbine formation in our Madison and Grimes counties area, $11.1 million related to drilling on our Elm Hill Project in Fayette and Gonzales counties, $9.1 million in drilling costs on our FRAMS and North Cheyenne Projects in Wyoming and $7.2 million for the acquisition of leases and other rights in new areas.

Our capital expenditure budget for 2015 is currently forecasted to be between $50 and $60 million, including the amounts spent during the six months ended June 30, 2015, and is expected to be funded primarily from internally generated cash flow.

Additionally, 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 we enter into will be successful. These potential investments are not part of our current capital budget and could require us to invest additional capital. Natural gas and oil prices continue to be volatile and our resources may not be sufficient to fund these opportunities.

Cash From Operating Activities

Cash flows from operating activities provided approximately $8.8 million in cash for the six months ended June 30, 2015 compared to providing $127.8 million for the same period in 2014. The table below provides additional detail of cash flows from operating activities for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Cash flows from operating activities, exclusive of changes in working capital accounts	$ 29,296	$ 111,951
Changes in operating assets and liabilities	(20,545)	15,897
Net cash provided by operating activities	$ 8,751	$ 127,848

Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations. The decrease for the six months ended June 30, 2015, compared to the same period in 2014, was the reduction in operating revenues reflecting the decrease in production volumes due to lower drilling activity and lower average realized sales prices. Changes in working capital also impact cash flows, and during the six months ended June 30, 2015, the working capital deficit was reduced primarily as a result of lower drilling activity.

Cash From Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2015 were approximately $56.8 million, all of which was used for capital expenditures related to drilling and/or completing wells and acquiring unproved leases in our areas of focus. Cash flows used in investing activities for the six months ended June 30, 2014 were approximately $103.9 million, including a $109.3 million outflow for capital expenditures related to drilling and completing wells, partially offset by a distribution of $5.4 million received during the period related to the sale of our Kaybob Duvernay Play.

Cash From Financing Activities

Cash flows provided by financing activities for the six months ended June 30, 2015 were approximately $48.0 million, primarily related to net borrowings under our credit facility with the Royal Bank of Canada and other lenders (the "RBC Credit Facility"). Cash flows used in financing activities for the six months ended June 30, 2014 were approximately $23.9 million, primarily related to partial repayment of borrowings outstanding under our RBC Credit Facility.

RBC Credit Facility

In October 2013, the Company entered into a $500 million four-year revolving credit facility with Royal Bank of Canada and other lenders with an initial hydrocarbon supported borrowing base of $275 million. Effective May 7, 2015, as part of the regular redetermination schedule, the borrowing base was redetermined at $225 million by the bank group due to lower commodity prices. The next regular scheduled redetermination will be November 1, 2015. The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require the maintenance of a minimum current ratio and a maximum leverage ratio. As of June 30, 2015, we were in compliance with all covenants under the RBC Credit Facility. See Note 8 to our Financial Statements – "Long-Term Debt" for further information regarding the RBC Credit Facility.

Application of Critical Accounting Policies and Management's Estimates

Significant accounting policies that we employ and information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate are presented in Note 2 to our Financial Statements – "Summary of Significant Accounting Policies" of this report and in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – "Application of Critical Accounting Policies and Management's Estimates" in our 2014 Form 10-K.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements, see Note 2 to our Financial Statements – "Summary of Significant Policies."

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of June 30, 2015, the primary off-balance sheet arrangements that we have entered into are operating lease agreements, which are customary in the oil and gas industry. Other than the off-balance sheet arrangements shown under operating leases in the commitments and contingencies table included in our 2014 Form 10-K, we have no other off-balance sheet arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk

We are exposed to various risks including energy commodity price risk for our natural gas and oil production. When oil, natural gas and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. Our major commodity price risk exposure is to the prices received. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for natural gas and oil are volatile and unpredictable. For the quarter ended June 30, 2015, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $3.5 million impact on our revenues.

Derivative Instruments and Hedging Activity

We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management strategy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our cash flows. The types of derivative instruments that we typically utilize include swaps and costless collars. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 40% to 50% of forecasted production from proved developed producing reserves (excluding forecasted offshore production during hurricane season), at the time of hedging, for the following twelve to eighteen months. Our hedge strategy and objectives may change significantly as our operational profile changes and/or commodity prices change.

We are exposed to market risk on our open derivative contracts related to potential nonperformance by our counterparties. It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The counterparties to the Company's current derivative contracts are large financial institutions and also lenders or affiliates of lenders in its RBC Credit Facility. We are not required to post collateral, or pay margin calls, under any of these contracts as they are secured under our RBC Credit Facility.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Currently, we do not have any derivative contracts to reduce the exposure to market rate fluctuations. At June 30, 2015, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. The estimated fair values for financial instruments under ASC 825, Financial Instruments (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Note 4 to our Financial Statements - "Derivative Instruments" for more details. As of June 30, 2015, we have 235 MBbl of crude oil production hedged between July 1, 2015 and December 31, 2015 at an average West Texas Intermediate floor price of $55.00/Bbl.

Interest Rate Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and US Prime based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

As of June 30, 2015, our total long-term debt was $111.4 million, which bears interest at a floating or market interest rate that is tied to the prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the quarter ended June 30, 2015, our effective rates fluctuated between 1.9 percent and 4.3 percent, depending on the term of the specific debt drawdowns. At June 30, 2015, we did not have any outstanding interest rate swap agreements. As of June 30, 2015, the weighted average interest rate on our variable rate debt was 2.04% per year. Assuming our current level of borrowings, a 100 basis point increase in the interest rates we pay under our RBC Credit Facility would result in an increase of our interest expense by $0.3 million for the three month period and $0.6 million for the six month period.

Other Financial Instruments

As of June 30, 2015, we had no cash or cash equivalents based on our cash management policy. 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 June 30, 2015, an immediate 10% change in interest rates would result in an immaterial change on our near-term financial condition or results of operations.

Item 4. Controls and Procedures

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 June 30, 2015. Based upon that evaluation, the Company's management concluded that, as of June 30, 2015, 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 six months ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, we are involved in legal proceedings relating to claims associated with our properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

Mineral interest owners in South Louisiana filed suit against a subsidiary of the Company and several co-defendants in June 2009 in the 31st Judicial District Court situated in Jefferson Davis Parish, Louisiana alleging failure to act as a reasonably prudent operator, failure to explore, waste, breach of contract, etc. in connection with two wells located in Jefferson Davis Parish. Many of the alleged improprieties occurred prior to our ownership of an interest in the wells at issue, although we may have assumed liability otherwise attributable to our predecessors-in-interest through the acquisition documents relating to the acquisition of our interest in these wells. We and our co-defendants obtained a favorable judgment from the trial court following a bench trial. In late 2014, the Louisiana Third Circuit Court of Appeals issued an opinion reversing the trial court's rulings and rendering judgment in favor of the plaintiffs for approximately $13.4 million. The decision by the court of appeals did not allocate liability among the defendants although we would likely be responsible for at least one-half, and possibly as much as two-thirds, of the judgment if it stands. We and our co-defendants filed an application for a writ of certiorari to the Louisiana Supreme Court seeking review of this case by the state's highest court. Our writ was granted in April 2015, although there remains uncertainty whether the Louisiana Supreme Court will rule in our favor. We and our co-defendants are vigorously defending this lawsuit and believe that we have a meritorious position. A companion case involving the same set of facts was filed in the same trial court on April 19, 2013 on behalf of additional mineral interest owners but has been inactive pending the appeal of the original case. Our potential exposure in this companion case is expected to be affected by the outcome of our appeal of the original case.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by us or by predecessor operators to which we have granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. We are vigorously defending this lawsuit, believe that we have meritorious defenses and are appealing the trial court's decision to the applicable state Court of Appeals.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). We have made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. We are vigorously defending this lawsuit and believe that we have meritorious defenses. We believe if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights we may have against other working interest and/or royalty interest owners in the unit.

In February 2011, a subsidiary of the Company and certain of our working interest partners and insurance carriers brought suit against a marine construction, dredging and tunneling company and an instrumentality of the United States of America in the U.S. District Court for the Southern District of Texas - Houston Division seeking monetary damages for damage to an offshore pipeline which was struck by a dredge. Following a bench trial in December 2013, we and our co-plaintiffs obtained a favorable judgment from the trial court. The U.S. Court of Appeals for the 5th Circuit affirmed the trial court's ruling in May 2015, and in July 2015, one of the co-defendants paid the full amount of the $13.9 million judgment (approximately $4.8 million net to us).

In May 2015, a subsidiary of the Company and several working interest partners settled a lawsuit with a mineral interest owner and a third-party operator pending in district court for Dimmit County, Texas. The suit involved a challenge from the mineral interest owner to the validity of an oil and gas lease and various other claims relating to the property subject to the lease. The settlement resulted in the subsidiary of the Company and its working interest partners receiving $5.0 million ($2.5 million net to us) in exchange for a release of their respective interests in the lease at issue.

While many of these matters involve inherent uncertainty and we are unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, we believe that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We maintain various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

Item 1A. Risk Factors

For discussion regarding our risk factors, see Item 1 of Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2014. Those risk and uncertainties are not the only ones facing us, and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations

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

None.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

(a) Exhibits:

The exhibits listed on the accompanying Exhibit Index are filed, furnished or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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: August 7, 2015	By:	/S/ ALLAN D. KEEL Allan D. Keel President and Chief Executive Officer (Principal Executive Officer)
Date: August 7, 2015	By:	/S/ E. JOSEPH GRADY E. Joseph Grady Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date: August 7, 2015	By:	/S/ DENISE DUBARD Denise DuBard Chief Accounting Officer and Controller (Principal Accounting Officer)

Exhibit Number	Description
2.1	Agreement and Plan of Merger, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Crimson Exploration Inc., dated as of April 29, 2013. (3)
3.1	Certificate of Incorporation of Contango Oil & Gas Company. (1)
3.2	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company. (2)
3.3	Third Amended and Restated Bylaws of Contango Oil & Gas Company. (4)
31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
101	Interactive Data Files †

† Filed herewith.

* Schedules to the agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company undertakes to furnish supplementally copies of any of the omitted schedules upon request by the SEC.

.

1. Filed as an exhibit to the Company's Current 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 Quarterly 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 Current Report on Form 8-K dated as of April 29, 2013, as filed with the Securities and Exchange Commission on May 1, 2013.

4. Filed as an exhibit to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on March 3, 2015.