CONTANGO OIL & GAS CO
Form 10-Q
November 04, 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 September 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 November 2, 2015 was 19,403,080.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2015

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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.

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Item 1. Consolidated Financial Statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	September 30, 2015	December 31, 2014
	(unaudited)	
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	21,335	25,309
Prepaid expenses and other	8,139	1,941
Inventory	540	2,166
Current deferred tax asset	—	1,624
Total current assets	30,014	31,040
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,184,699	1,138,054
Unproved properties	23,732	35,783
Other property and equipment	1,133	1,084
Accumulated depreciation, depletion and amortization	(764,789)	(426,298)
Total property, plant and equipment, net	444,775	748,623
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	61,369	62,085
Other	1,214	1,667
Total other non-current assets	62,583	63,752
TOTAL ASSETS	$ 537,372	$ 843,415
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 47,445	$ 92,892
Current asset retirement obligations	6,417	4,123
Total current liabilities	53,862	97,015

NON-CURRENT LIABILITIES:		
Long-term debt	114,569	63,359
Deferred tax liability	—	93,952
Asset retirement obligations	20,314	21,623
Total non-current liabilities	134,883	178,934
Total liabilities	188,745	275,949
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 24,644,924 shares issued and 19,410,700 shares outstanding at September 30, 2015, 24,372,538 shares issued and 19,148,000 shares outstanding at December 31, 2014	974	963
Additional paid-in capital	238,276	233,278
Treasury shares at cost (5,234,224 shares at September 30, 2015 and 5,224,538 shares at December 31, 2014)	(127,596)	(127,525)
Retained earnings	236,973	460,750
Total shareholders' equity	348,627	567,466
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 537,372	$ 843,415

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(unaudited)		(unaudited)	
REVENUES:				
Oil and condensate sales	$ 9,500	$ 37,662	$ 35,882	$ 111,102
Natural gas sales	16,020	21,676	48,130	87,547
Natural gas liquids sales	3,515	8,214	11,004	27,579
Total revenues	29,035	67,552	95,016	226,228
EXPENSES:				
Operating expenses	9,036	13,797	29,919	36,426
Exploration expenses	407	(4,713)	11,814	33,071
Depreciation, depletion and amortization	38,386	40,550	112,271	114,853
Impairment and abandonment of oil and gas properties	235,150	6,693	237,667	23,259
General and administrative expenses	7,504	6,821	22,683	26,485
Total expenses	290,483	63,148	414,354	234,094
OTHER INCOME (EXPENSE):				
Gain (loss) from investment in affiliates (net of income taxes)	(375)	1,287	(562)	4,387
Interest expense	(785)	(672)	(2,315)	(2,077)
Gain (loss) on derivatives, net	2,011	1,734	2,001	(1,488)
Other income (expense)	4,288	48	5,278	(148)
Total other income	5,139	2,397	4,402	674
NET INCOME (LOSS) BEFORE INCOME TAXES	(256,309)	6,801	(314,936)	(7,192)
Income tax benefit (provision)	70,624	(3,137)	91,159	5,244
NET INCOME (LOSS)	$ (185,685)	$ 3,664	$ (223,777)	$ (1,948)
NET INCOME (LOSS) PER SHARE:				
Basic	$ (9.79)	$ 0.19	$ (11.81)	$ (0.10)
Diluted	$ (9.79)	$ 0.19	$ (11.81)	$ (0.10)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	18,966	19,077	18,948	19,074
Diluted	18,966	19,122	18,948	19,074

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)

	Nine Months Ended September 30, 2015	2014
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (223,777)	$ (1,948)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	112,271	114,853
Impairment of natural gas and oil properties	237,656	22,688
Exploration expenses	6,826	31,594
Deferred income taxes	(92,328)	(3,485)
Loss on sale of assets	231	—
Loss (gain) from investment in affiliates	865	(6,750)
Stock-based compensation	5,008	3,333
Unrealized gain on derivative instruments	(999)	(1,494)
Changes in operating assets and liabilities:		
Decrease in accounts receivable and other receivables	3,581	18,703
Increase in prepaid expenses	(5,198)	(606)
Increase (decrease) in accounts payable and advances from joint owners	(25,373)	2,393
Decrease in other accrued liabilities	(1,494)	(2,489)
Decrease in income taxes receivable, net	748	466
Other	1,233	(422)
Net cash provided by operating activities	$ 19,250	$ 176,836
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (70,389)	$ (146,699)
Distributions from affiliates	—	5,365
Net cash used in investing activities	$ (70,389)	$ (141,334)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 284,378	$ 352,558
Repayments under credit facility	(233,168)	(388,144)
Proceeds from exercised options	—	120
Excess tax benefit from exercise of stock options	—	3

Purchase of treasury stock	(71)	(4)
Debt issuance costs	—	(35)
Net cash provided by (used in) financing activities	$ 51,139	$ (35,502)
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	Common Stock 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	(9,686)	—	—	(71)	—	(71)
Restricted shares activity	272,386	11	(10)	—	—	1
Stock-based compensation	—	—	5,008	—	—	5,008
Net loss	—	—	—	—	(223,777)	(223,777)
Balance at September 30, 2015	19,410,700	$ 974	$ 238,276	$ (127,596)	$ 236,973	$ 348,627

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 September 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 Dimmit counties, Texas	Buda / Austin Chalk
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 reported production results for the three or nine months ended September 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 focused 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.

The following table lists the primary areas to which the Company has allocated 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 nine months ended September 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, reserves or production in those reported for the Company's consolidated results.

Impairment of Long-Lived Assets

Pursuant to GAAP, 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. The Company recognized approximately $225.6 million and $227.6 million for impairment of proved properties for the three and nine months ended September 30, 2015, respectively. Substantially all of the non-cash impairment charge in the quarter ended September 30, 2015 is directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Approximately $196.5 million of the total proved property impairment for both the three and the nine months ended September 30, 2015 is attributable to the Madison/Grimes counties and Zavala/Dimmit/Karnes counties properties. No impairment of proved properties was recognized for the three and nine months ended September 30, 2014.

If oil and/or natural gas prices decline further from forecasted strip prices existing at September 30, 2015, and upon which the third quarter impairment was calculated, we may be required to record additional non-cash impairment in the future, thereby impacting our financial results for that period.

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 $9.5 million and $10.1 million for the three and nine months ended September 30, 2015, respectively, related to impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases. Approximately $8.2 million of the total for the three and nine months ended September 30, 2015 is related to unproved lease cost amortization of the Elm Hill project in Fayette and Gonzales counties Texas.

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 nine months ended September 30, 2014, the Company recognized a total of $31.6 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.

The Company recognized impairment expense of approximately $6.7 million and $7.1 million for the three and nine month periods ended September 30, 2014, respectively, related to impairment and partial impairment of certain unproved properties due to expiring leases and leases not likely to be drilled.

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. 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 nine months ended September 30, 2015, 127,613 stock options and 423,820 restricted shares were excluded from dilutive shares due to the loss for the period. For the three months ended September 30, 2014, 114,934 stock options and 98,269 restricted shares were excluded from dilutive shares as they were antidilutive. For the nine months ended September 30, 2014, 130,348 stock options and 299,501 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 September 2015, the FASB issued Accounting Standards Update No. 2015-16: Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments (ASU 2015-16). ASU 2015-16 is part of an initiative to reduce complexity in accounting standards, and requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. In addition, the amendments of this update require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the changes to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. Furthermore, ASU 2015-16 requires an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustments to the provisional amounts had been recognized as of the acquisition date. For public entities, ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. 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 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 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 conditions 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 September 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 September 30, 2015 (in thousands):

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$ 999	$ —	$ 999	$ —
Commodity price contracts - liabilities	$ —	$ —	$ —	$ —

Derivatives listed above are recorded in “Prepaid expenses and other” on the Company’s consolidated balance sheet and include collars that are carried at fair value. The Company records the net change in the fair value of these positions in "Gain (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 September 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 reset at least every three months. See Note 8 - "Long-Term Debt" for further information.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The Company tests its proved oil and natural gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. An impairment loss is indicated if the sum of the expected 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. In this circumstance, the capitalized cost is reduced to fair value.

For the three and nine months ended September 30, 2015, the Company recognized approximately $225.6 million and $227.6 million for impairment of proved properties, respectively. Substantially all of the non-cash impairment charge in the quarter ended September 30, 2015 is directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves and (iv) results of future drilling activities.

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 September 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 "Gain (loss) on derivatives, net" on the consolidated statements of operations.

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

Commodity	Period	Derivative	Volume/Month	Price/Unit (1)	Fair Value
Crude Oil	Oct 2015 - Dec 2015	Collar	35,000 Bbls	$55.00 - $65.15	999
		Total net fair value of derivative instruments			$ 999

(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 September 30, 2015 (in thousands):

	Gross	Netting (1)	Total
Assets	$ 999	$ —	$ 999
Liabilities	$ —	$ —	$ —

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

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The following table summarizes the effect of derivative contracts on the consolidated statements of operations for the three and nine months ended September 30, 2015 and 2014 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Crude oil contracts	$ 1,002	$ (214)	$ 1,002	$ (1,385)
Natural gas contracts	—	(15)	—	(1,597)
Realized gain (loss)	$ 1,002	$ (229)	$ 1,002	$ (2,982)
Crude oil contracts	$ 1,009	$ 1,773	$ 999	$ 1,538
Natural gas contracts	—	190	—	(44)
Unrealized gain	$ 1,009	$ 1,963	$ 999	$ 1,494
Gain (loss) on derivatives, net	$ 2,011	$ 1,734	$ 2,001	$ (1,488)

5. Stock-Based Compensation

During the nine months ended September 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 nine months ended September 30, 2015, there was no excess tax benefit recognized. For the nine months ended September 30, 2014, there was an insignificant 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 nine months ended September 30, 2015 or 2014.

During the nine months ended September 30, 2015, no stock options were exercised and stock options for 2,321 shares of common stock were forfeited by former employees. During the nine months ended September 30, 2014, 4,165 stock options were exercised and stock options for 594 shares of common stock were forfeited.

Restricted Stock

During the nine months ended September 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 nine months ended September 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 September 30, 2015.

During the nine months ended September 30, 2015, 4,735 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the nine months ended September 30, 2015 was approximately $147 thousand.

During the nine months ended September 30, 2015, the Company recognized approximately $5.0 million in stock-based compensation expense for the vesting of restricted shares previously granted to its officers, employees and directors. Included in this amount was approximately $1.1 million related to the accelerated vesting of restricted shares due to a reduction in force implemented in August of 2015. As of September 30, 2015, an additional $8.5 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 2.4 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):

	September 30, 2015	December 31, 2014
Accounts receivable:		
Trade receivable	$ 9,637	$ 13,926
Receivable for Alta Resources distribution	1,993	1,993
Joint interest billing	6,091	4,096
Income taxes receivable	2,868	3,274
Other receivables	1,323	2,610
Allowance for doubtful accounts	(577)	(590)
Total accounts receivable	$ 21,335	$ 25,309
Prepaid expenses and other:		
Prepaid insurance	$ 1,417	$ 1,242
Deposit (1)	5,000	—
Other	1,722	699
Total prepaid expenses and other	$ 8,139	$ 1,941
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 21,035	$ 31,653
Accrued exploration and development	7,127	26,538
Trade payables	7,151	17,282
Advances from partners	3,504	8,334
Accrued general and administrative expenses	4,194	6,258
Other accounts payable and accrued liabilities	4,434	2,827
Total accounts payable and accrued liabilities	$ 47,445	$ 92,892

(1) Non-refundable deposit related to potential asset purchase.

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

	Nine Months Ended September 30,	
	2015	2014
Cash payments:		
Interest payments	2,231	2,224
Income tax payments	100	136

Non-cash investing activities in the consolidated statements of cash flows:		
Decrease in accrued capital expenditures	(19,411)	(3,677)

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 nine months ended September 30, 2015.

The following table (in thousands) presents condensed balance sheet data for Exaro as of September 30, 2015 and December 31, 2014. The balance sheet data was derived from Exaro's balance sheet as of September 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 September 30, 2015 was approximately $60.3 million.

	September 30, 2015	December 31, 2014
Current assets	$ 27,534	$ 35,013
Non-current assets:		
Net property and equipment	226,286	233,997
Restricted cash escrow account	—	577
Other non-current assets	659	1,779
Total non-current assets	226,945	236,353
Total assets	$ 254,479	$ 271,366
Current liabilities	$ 4,369	$ 9,405
Non-current liabilities:		
Long-term debt	84,500	94,500
Other non-current liabilities	1,576	1,084
Total non-current liabilities	86,076	95,584
Members' equity	164,034	166,377
Total liabilities & members' equity	$ 254,479	$ 271,366

The following table (in thousands) presents the condensed results of operations for Exaro for the three and nine months ended September 30, 2015 and 2014. The results of operations for the three and nine months ended September 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 September 30, 2015 and 2014 was a loss of $0.4 million, net of tax benefit of $0.2 million, and a gain of $1.3 million, net of tax expense of $0.7 million, respectively. The Company's share of Exaro's results of operations recognized for the nine months ended September 30, 2015 and 2014 was a loss of $0.6 million, net of tax benefit of $0.3 million, and a gain of $4.4 million, net of tax expense of $2.4 million, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production:				
Oil (thousand barrels)	40	42	127	125
Gas (million cubic feet)	3,236	3,371	9,928	9,824
Total (million cubic feet equivalent)	3,477	3,627	10,691	10,576

Oil and natural gas sales	$ 7,881	$ 19,090	$ 31,731	$ 61,380
Other gain (loss)	3,667	955	3,608	(1,037)
Less:				
Lease operating expenses	4,467	5,463	12,946	16,875
Depreciation, depletion, amortization & accretion	7,229	7,294	20,147	19,420
General & administrative expense	724	730	2,586	2,680
Income (loss) from continuing operations	(872)	6,558	(340)	21,368
Net interest expense	(689)	(1,195)	(2,243)	(3,161)
Net income (loss)	$ (1,561)	$ 5,363	$ (2,583)	$ 18,207

Included in Other gain (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.

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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. As part of the regular redetermination schedule, the Company's bank group redetermined the Company's borrowing base at $225 million effective May 7, 2015, primarily due to lower commodity prices and the impact of the significant reduction in the Company's drilling program in 2015. The next regular scheduled redetermination is expected to be completed mid-November. Due to the lower commodity price environment and the reduced capital program, the Company expects some reduction in the borrowing base. Based on preliminary discussions with its agent bank and their borrowing base recommendation currently being considered by the remaining lenders under the facility, the Company expects that the proposed borrowing base will not impact its liquidity position in a material adverse way.

As of September 30, 2015 and December 31, 2014, the Company had approximately $114.6 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 September 30, 2015, borrowing availability under the RBC Credit Facility was $108.5 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 nine months ended September 30, 2015 was approximately $0.8 million and $2.3 million, respectively. Total interest expense under the RBC Credit Facility, including commitment fees, for the three and nine months ended September 30, 2014 was approximately $0.7 million and $2.1 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 September 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. As a condition to borrow funds or issue letters of credit under the RBC Credit Facility, the Company must remain in compliance with the restrictive covenants. The Company also must make certain representations and warranties to its bank lenders at the time of each borrowing, including representations about the Company's solvency. If the Company does not meet its financial ratios or is unable to give the required representations, then the Company will need a waiver or amendment from its bank lenders in order to continue to be able to borrow or issue letters of credit under the RBC Credit Facility. Although the Company believes its bank lenders are well secured under the terms of the RBC Credit Facility, there is no assurance that the bank lenders would provide any waiver or amendment in the future should either become conditions to further lending.

The weighted average interest rate in effect at September 30, 2015 and December 31, 2014 was 2.12% 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Current tax provision (benefit):				
Federal	$ —	$ —	$ —	$ (524)
State	(5)	414	517	1,127
Total	$ (5)	$ 414	$ 517	$ 603
Deferred tax provision (benefit):				
Federal	$ (70,631)	$ 3,651	$ (91,254)	$ (2,775)
State	(191)	(235)	(725)	(710)
Total	$ (70,822)	$ 3,416	$ (91,979)	$ (3,485)
Total tax provision (benefit):				
Federal	$ (70,631)	$ 3,651	$ (91,254)	$ (3,299)
State	(196)	179	(208)	417
Total	$ (70,827)	$ 3,830	$ (91,462)	$ (2,882)
Included in gain (loss) from investment in affiliates	$ (203)	$ 693	$ (303)	$ 2,362
Total income tax provision (benefit)	$ (70,624)	$ 3,137	$ (91,159)	$ (5,244)

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that the deferred tax assets will be realized and, therefore, has established a valuation allowance of $17.5 million to reduce the net deferred tax asset to zero at September 30, 2015. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

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; Mr. Juneau served on the Board of Managers of Exaro; and 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. 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 September 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 nine months ended September 30, 2015, Mr. Romano earned $13 thousand and $66 thousand, respectively, for his service as a director of the Company. During the three and nine months ended September 30, 2014, Mr. Romano earned $26 thousand and $78 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 $20 thousand and $82 thousand related to the shares granted to Mr. Romano for the three and nine months ended September 30, 2015, respectively. During the three and nine months ended September 30, 2014, the Company recognized compensation expense of approximately $44 thousand and $80 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 $2.6 million related to this bonus is included in general and administrative expenses for the nine months ended September 30, 2014.

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 September 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$ (1,173)	$ (728)	$ (240)	$ (1,555)	$ (1,039)	$ (489)
Joint interest billing receipts	99	71	113	136	253	89

	Nine Months Ended September 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$ (3,314)	$ (2,087)	$ (735)	$ (5,767)	$ (3,851)	$ (1,835)
Joint interest billing receipts	388	298	181	418	411	245

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 September 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$ —	$ —	$ —	$ —	$ —	$ —
Rent received for sublease	—	—	—	—	44	—

	Nine Months Ended September 30,					
	2015			2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$ —	$ —	$ —	$ (54)	$ (29)	$ —
Rent received for sublease	—	119	—	—	110	—

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

	September 30, 2015			December 31, 2014		
	Olympic	JEX	REX	Olympic	JEX	REX
Accounts receivable:						
Joint interest billing	$ 25	$ 28	$ 20	$ 48	$ 42	$ 12
Accounts payable:						
Royalties and revenue payable	(608)	(381)	(128)	(1,006)	(620)	(175)

Oaktree Capital Management L.P.

As of September 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 nine months ended September 30, 2015, the affiliate of Oaktree earned $15 thousand and $47 thousand in cash as a result of Mr. Ford's board participation, and the Company recognized compensation expense of approximately $20 thousand and $82 thousand related to the shares of restricted stock previously granted to an affiliate of Oaktree under the Director Compensation Plan. During the three and nine months ended September 30, 2014, the affiliate of Oaktree earned $16 thousand and $48 thousand in cash as a result of Mr. Ford's board participation, and the Company recognized compensation expense of approximately $44 thousand and $80 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's subsidiary would likely be responsible for at least one-half, and possibly as much as two-thirds, of the judgment if it stands. The Louisiana Supreme Court is currently reviewing this case, although there remains uncertainty whether the Louisiana Supreme Court will rule in the Company's 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. In August, the trial court entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds, although indications are that the plaintiff will appeal the trial court's decision to the applicable state Court of Appeals. 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.

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 of 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 September 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 Dimmit counties, Texas	Buda / Austin Chalk
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 reported production results for the three or nine months ended September 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 focused 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.

The following table lists the primary areas to which we have allocated 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

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Drilling Activity

As previously disclosed, due to the low and uncertain commodity price environment, we strategically reduced our drilling program for 2015 after the first quarter to two wells in process in our Fayette and Gonzales counties, Texas and to two delineation wells in our Weston County, Wyoming play.

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). Based on the encouraging results from this well, we spud two more wells in September 2015, the WC 45N-66W-35 1H and the WC 44N-66W-9 1H. Both wells are currently in various stages of drilling or completion. We have approximately 49,000 gross acres (35,000 net) in this area. Our 2016 drilling program for this area will be developed based on results of the wells in process and the commodity price environment. 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.

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 area. As of September 30, 2015, we had drilled and completed five gross (2.5 net) wells in the Navarro, Buda and Austin Chalk formations, and were producing from two of these wells; the other three wells were not commercial successes. We have recovered four whole cores to further evaluate six hydrocarbon bearing formations that we believe might have potential for development. We and our partner are discussing future plans for this area.

Other Texas Counties

No drilling activity was conducted in Madison, Grimes, Zavala or Dimmit counties, Texas during the quarter ended September 30, 2015, as we opted to stay within internally generated cash flows to further delineate our Wyoming and Fayette County plays. Within the past year as part of our planned strategy, we have taken several whole core samples in Madison, Grimes, Zavala and Dimmit counties, to evaluate several zones, and are encouraged by their log results. Once commodity prices improve and/or service costs decline, we may increase our activity in these areas. We believe we have a multi-year inventory of potential drilling locations, targeting the Woodbine, Eagle Ford Shale, Buda and other formations.

Impairment of Long-Lived Assets

We recognized approximately $235.1 million in non-cash impairment charges in the current quarter primarily related to the reduction in the estimated value of future net cash flows of the Company’s risk adjusted proved, probable and possible reserves (3P reserves) due to the recent dramatic decline in commodity prices for crude oil and natural gas. Under Financial Accounting Standards Board Accounting Codifications, an impairment charge is required when the unamortized capital cost of any individual property within the company’s producing property base exceeds the risked estimated future net cash flows from the 3P reserves for that property. Substantially all of the impairment expense recognized in the quarter related to the onshore properties acquired via a stock-for-stock merger with Crimson Exploration Inc. in October 2013. Pursuant to accounting principles generally accepted in the United States of

America ("GAAP") merger accounting rules, we were required to allocate the purchase price to the fair market value of the Crimson properties as our capitalized producing property cost for each property, i.e. rather than Crimson's actual unamortized cash historical finding and development cost. The commodity price environment used for determining fair market value of each property at the time of the merger was considerably higher than it is currently; therefore, we recorded an incremental $195.7 million in asset cost in excess of Crimson's unamortized capital cost (an upward purchase price adjustment "PPA") for Crimson's highest value properties, i.e. its Madisonville/Grimes counties assets and its Zavala/Dimmit/Karnes counties assets, and that incremental value has been subject to amortization post-merger. Approximately $64.2 million of the PPA for those properties has been amortized post-merger through quarterly depreciation, depletion and amortization ("DD&A"), thereby reflecting a higher overall DD&A rate than would have been recognized through amortization of the actual cash cost incurred in finding and developing those assets. Substantially all of the impairment charge in this quarter is directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Approximately $196.5 million of the $235.1 million total impairment is attributable to our Madison/Grimes counties and Zavala/Dimmit/Karnes counties properties, including approximately $124.8 million of which is the unamortized PPA recorded on those properties as part of the merger accounting. Also included in the impairment charge for the quarter is approximately $10.0 million related to producing property impairment and $8.2 million related to unproved lease cost amortization on our Elm Hill project in Fayette and Gonzales counties Texas.

If oil and/or natural gas prices decline further from forecasted strip prices existing at September 30, 2015, and upon which the third quarter impairment was calculated, we may be required to record additional non-cash impairment in the future, thereby impacting our financial results for that period.

Summary Production Information

Our production for the three months ended September 30, 2015 was approximately 63% offshore and 37% onshore, and 67% natural gas, 15% oil and 18% natural gas liquids. Our production for the three months ended September 30, 2014 was 54% offshore and 46% onshore, and approximately 60% natural gas, 25% oil and 15% 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 September 30, 2014		December 31, 2014	March 31, 2015	June 30, 2015	September 30, 2015
Offshore GOM						
Dutch and Mary Rose	42.3	(5)	55.9	53.3	50.8	49.5
Vermilion 170	8.0		5.7	7.7	6.3	7.0
Other offshore (1)	5.2		6.5	3.2	1.6	0.5
Southeast Texas (2)	26.6		23.6	19.3	28.2	22.9
South Texas (3)	17.4		12.2	10.8	9.3	8.9
Other (4)	2.8		2.3	2.0	2.2	2.1
	102.3		106.2	96.3	98.4	90.9

(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) Lower mainly due 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 September 30, 2015, Contaro had invested approximately $46.9 million in Exaro.

As of September 30, 2015, Exaro had 645 wells on production over its 5,760 gross acres (1,040 net), with a working interest between 14.6% and 32.5%. These wells were producing at a rate of approximately 39 Mmcfed, net to Exaro. There are currently no wells in the completion or fracture stimulation phase. The operator expects to have no drilling rigs running on this project during the remainder of 2015. For the quarter ended September 30, 2015, we recognized a net investment loss of approximately $0.4 million, net of tax benefit of $0.2 million, as a result of our investment in Exaro. For the quarter ended September 30, 2014, we recognized a net investment gain of approximately $1.3 million, net of tax expense of $0.7 million. For the nine months ended September 30, 2015, we recognized a net investment loss of approximately $0.6 million, net of tax benefit of $0.3 million, as a result of our investment in Exaro. For the nine months ended September 30, 2014, we recognized a net investment gain of approximately $4.4 million, net of tax expense of $2.4 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 Nine Months Ended September 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 nine months ended September 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 September 30,			Nine Months Ended September 30,		
	2015	2014	%	2015	2014	%
Revenues:	(thousands except prices)			(thousands except prices)		
Oil and condensate sales	$ 9,500	$ 37,662	(75)%	$ 35,882	$ 111,102	(68)%
Natural gas sales	16,020	21,676	(26)%	48,130	87,547	(45)%
NGL sales	3,515	8,214	(57)%	11,004	27,579	(60)%
Total revenues	$ 29,035	$ 67,552	(57)%	$ 95,016	$ 226,228	(58)%
Production:						
Oil and condensate (thousand barrels)						
Offshore GOM	42	57	(26)%	149	211	(29)%
Southeast Texas	110	208	(47)%	400	586	(32)%
South Texas	47	114	(59)%	142	282	(50)%
Other	14	13	8 %	39	51	(24)%
Total oil and condensate	213	392	(46)%	730	1,130	(35)%
Natural gas (million cubic feet)						
Offshore GOM	4,191	4,039	4 %	13,117	14,302	(8) %
Southeast Texas	869	762	14 %	2,342	2,464	(5) %
South Texas	420	663	(37)%	1,384	1,909	(28)%
Other	100	173	(42)%	317	523	(39)%
Total natural gas	5,580	5,637	(1) %	17,160	19,198	(11)%
Natural gas liquids (thousand barrels)						
Offshore GOM	133	121	10 %	392	439	(11)%
Southeast Texas	96	73	32 %	276	218	27 %
South Texas	19	42	(55)%	67	98	(32)%
Other	2	2	— %	5	7	(29)%
Total natural gas liquids	250	238	5 %	740	762	(3) %
Total (million cubic feet equivalent)						
Offshore GOM	5,244	5,104	3 %	16,367	18,201	(10)%
Southeast Texas	2,105	2,447	(14)%	6,401	7,293	(12)%
South Texas	816	1,597	(49)%	2,636	4,191	(37)%

Other	194	268	(28)%	578	868	(33)%
Total production	8,359	9,416	(11)%	25,982	30,553	(15)%
Daily Production:						
Oil and condensate (thousand barrels per day)						
Offshore GOM	0.4	0.6	(26)%	0.5	0.8	(29)%
Southeast Texas	1.2	2.3	(47)%	1.5	2.1	(32)%
South Texas	0.5	1.2	(59)%	0.5	1.0	(50)%
Other	0.2	0.2	8 %	0.2	0.2	(24)%
Total oil and condensate	2.3	4.3	(46)%	2.7	4.1	(35)%
Natural gas (million cubic feet per day)						
Offshore GOM	45.6	43.9	4 %	48.0	52.4	(8) %
Southeast Texas	9.4	8.3	14 %	8.6	9.0	(5) %
South Texas	4.6	7.2	(37)%	5.1	7.0	(28)%
Other	1.1	1.9	(42)%	1.2	1.9	(39)%
Total natural gas	60.7	61.3	(1) %	62.9	70.3	(11)%

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	%	2015	2014	%
Natural gas liquids (thousand barrels per day)	(thousands except prices)			(thousands except prices)		
Offshore GOM	1.5	1.3	10 %	1.5	1.6	(11) %
Southeast Texas	1.0	0.8	32 %	1.0	0.8	27 %
South Texas	0.2	0.5	(55) %	0.2	0.4	(32) %
Other	—	—	— %	—	—	(29) %
Total natural gas liquids	2.7	2.6	5 %	2.7	2.8	(3) %
Total (million cubic feet equivalent per day)						
Offshore GOM	57.0	55.5	3 %	60.0	66.7	(10) %
Southeast Texas	22.9	26.6	(14) %	23.4	26.7	(12) %
South Texas	8.9	17.4	(49) %	9.7	15.4	(37) %
Other	2.1	2.8	(28) %	2.1	3.1	(33) %
Total production	90.9	102.3	(11) %	95.2	111.9	(15) %
Average Sales Price:						
Oil and condensate (per barrel)	$ 44.56	$ 96.05	(54) %	$ 49.14	$ 98.32	(50) %
Natural gas (per thousand cubic feet)	$ 2.87	$ 3.85	(25) %	$ 2.80	$ 4.56	(39) %
Natural gas liquids (per barrel)	$ 14.05	$ 34.55	(59) %	$ 14.86	$ 36.17	(59) %
Total (per thousand cubic feet equivalent)	$ 3.47	$ 7.17	(52) %	$ 3.66	$ 7.40	(51) %
Expenses:						
Operating expenses	$ 9,036	$ 13,797	(35) %	$ 29,919	$ 36,426	(18) %
Exploration expenses	$ 407	$ (4,713)	(109)%	$ 11,814	$ 33,071	(64) %
Depreciation, depletion and amortization	$ 38,386	$ 40,550	(5) %	$ 112,271	$ 114,853	(2) %
Impairment and abandonment of oil and gas properties	$ 235,150	$ 6,693	** %	$ 237,667	$ 23,259	922 %
General and administrative expenses	$ 7,504	$ 6,821	10 %	$ 22,683	$ 26,485	(14) %
Gain (loss) from investment in affiliates (net of taxes)	$ (375)	$ 1,287	(129)%	$ (562)	$ 4,387	(113)%
Selected data per Mcfe:						
Operating expenses	$ 1.08	$ 1.47	(27) %	$ 1.15	$ 1.19	(3) %
General and administrative expenses	$ 0.90	$ 0.72	25 %	$ 0.87	$ 0.87	— %
Depreciation, depletion and amortization	$ 4.59	$ 4.31	6 %	$ 4.32	$ 3.76	15 %

** Greater than 1000%.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 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 $29.0 million for the three months ended September 30, 2015, compared to revenues of $67.6 million for the three months ended September 30, 2014. The decrease in revenues was primarily attributable to: (i) a significant decline in commodity prices, which contributed approximately $21.5 million of the decrease in revenues and (ii) approximately $17.0 million due to lower production volumes resulting from a commodity price related reduction in drilling.

Total equivalent production declined from 102.3 Mmcfed to 90.9 Mmcfed, a decrease attributable primarily to an 8.5 Mmcfed decline in South Texas production and a 3.7 Mmcfed decline in Southeast Texas production, both 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 September 30, 2015 was $3.47 per Mcfe compared to $7.17 per Mcfe for the three months ended September 30, 2014. This decrease was attributable primarily to the decrease in the realized price of oil to $44.56 per barrel, compared to $96.05 per barrel for the three months ended September 30, 2014, and to the decrease in the realized price of natural gas to $2.87 per Mcf, compared to $3.85 per Mcf for the three months ended September 30, 2014.

Operating Expenses

Operating expenses for the three months ended September 30, 2015 were approximately $9.0 million, or $1.08 per Mcfe, compared to $13.8 million, or $1.47 per Mcfe, for the three months ended September 30, 2014. The table below provides additional detail of operating expenses for the three months ended September 30, 2015 and 2014:

	Three Months Ended September 30,			
	2015		2014	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 5,864	$ 0.70	$ 7,684	$ 0.82
Production & ad valorem taxes	814	0.10	3,201	0.34
Transportation & processing costs	1,270	0.15	1,875	0.20
Workover costs	1,088	0.13	1,037	0.11
Total operating expenses	$ 9,036	$ 1.08	$ 13,797	$ 1.47

Lease operating expenses decreased by 24% for the three months ended September 30, 2015, compared to the three months ended September 30, 2014, as a direct result of our efforts to reduce costs during this challenging commodity price environment.

Production and ad valorem taxes decreased by 75% for the three months ended September 30, 2015, compared to the three months ended September 30, 2014, primarily due to the decrease in revenues for the same periods.

Exploration Expenses

Exploration expenses for the three months ended September 30, 2015 were approximately $0.4 million. Exploration expenses for the three months ended September 30, 2014 included a $5.2 million credit related to a downward adjustment to estimated costs for Ship Shoal 255 accrued in the previous quarter.

Impairment Expenses

Impairment expenses for the three months ended September 30, 2015 included a $225.6 million impairment of proved properties. Substantially all of the non-cash impairment charge in the quarter ended September 30, 2015 is directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Approximately $196.5 million of the total proved property impairment for the three months ended September 30, 2015 is attributable to the Madison/Grimes counties and Zavala/Dimmit/Karnes counties properties. No impairment of proved properties was recognized for the three months ended September 30, 2014.

Impairment expenses for the three months ended September 30, 2015 included a $9.5 million impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases. Approximately $8.2 million of the total for the three months ended September 30, 2015 is related to unproved lease cost amortization of the Elm Hill project in Fayette and Gonzales counties Texas.

Impairment expense for the three months ended September 30, 2014 included a $6.7 million impairment and partial impairment of certain unproved prospects due to expiring leases and leases not likely to be drilled.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended September 30, 2015 was approximately $38.4 million or $4.59 per Mcfe. This compares to approximately $40.6 million or $4.31 per Mcfe for the three months ended September 30, 2014. The increase in the 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 September 30, 2015 were approximately $7.5 million, compared to $6.8 million for the three months ended September 30, 2014. General and administrative expenses for the three months ended September 30, 2015 included approximately $2.4 million in non-cash stock based compensation, while the prior year quarter included $1.2 million in non-cash stock based compensation. Also included in the current year quarter was approximately $0.6 million in cash severance costs resulting from an August 2015 reduction in staff. Exclusive of the severance costs, cash general and administrative expenses for the current year quarter were $4.5 million, compared to cash expenses of $5.6 million for the prior year quarter. The reduction in force was a major step in our ongoing cost cutting efforts necessitated by the current challenging commodity price environment.

Loss/Gain from Affiliates

For the three months ended September 30, 2015, the Company recorded a loss from affiliates of approximately $0.4 million, net of tax benefit of $0.2 million, related to our investment in Exaro, compared to a gain of $1.3 million, net of tax expense of $0.7 million, for the three months ended September 30, 2014.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 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 $95.0 million for the nine months ended September 30, 2015, compared to revenues of $226.2 million for the nine months ended September 30, 2014. The decrease in revenues was primarily attributable to: (i) a significant decline in commodity prices, which contributed approximately $81.8 million of the decrease in revenues and (ii) approximately $49.4 million due to lower production volumes resulting from a reduction in drilling due to the low-price environment.

Total equivalent production declined from 111.9 Mmcfed to 95.2 Mmcfed, a decrease attributable primarily to typical field decline (approximately 6.7 Mmcfed) in our Gulf of Mexico production and a 5.7 Mmcfed and 3.3 Mmcfed decline in South Texas and Southeast Texas production, respectively, 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 nine months ended September 30, 2015 was $3.66 per Mcfe compared to $7.40 per Mcfe for the nine months ended September 30, 2014. This decrease was attributable primarily to the decrease in the realized price of oil to $49.14 per barrel, compared to $98.32 per barrel for the nine months ended September 30, 2014, and to the decrease in the realized price of natural gas to $2.80 per Mcf, compared to $4.56 per Mcf for the nine months ended September 30, 2014.

Operating Expenses

Operating expenses for the nine months ended September 30, 2015 were approximately $29.9 million, or $1.15 per Mcfe, compared to $36.4 million, or $1.19 per Mcfe, for the nine months ended September 30, 2014. The table below provides additional detail of operating expenses for the nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,			
	2015		2014	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 19,484	$ 0.75	$ 20,612	$ 0.68
Production & ad valorem taxes	3,751	0.14	9,264	0.30
Transportation & processing costs	3,891	0.15	4,589	0.15
Workover costs	2,793	0.11	1,961	0.06
Total operating expenses	$ 29,919	$ 1.15	$ 36,426	$ 1.19

Production and ad valorem taxes decreased by 60% for the nine months ended September 30, 2015, compared to the nine months ended September 30, 2014, primarily due to the decrease in revenues for the same periods.

Exploration Expenses

Exploration expenses for the nine months ended September 30, 2015 were approximately $11.8 million, which included $6.5 million in dry-hole costs related to our State #1H well in Natrona County, Wyoming, and $3.2 million related to the early termination of a drilling rig contract. Exploration expenses for the nine months ended September 30, 2014 included approximately $31.6 million in dry-hole costs related to our Ship Shoal 255 well finalized during the second quarter.

Impairment Expenses

Impairment expenses for the nine months ended September 30, 2015 included a $227.6 million impairment of proved properties. Substantially all of the non-cash impairment charge in the nine months ended September 30, 2015 is directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Approximately $196.5 million of the total proved property impairment for the nine months ended September 30, 2015 is attributable to the Madison/Grimes counties and Zavala/Dimmit/Karnes counties properties. No impairment of proved properties was recognized for the nine months ended September 30, 2014.

Impairment expenses for the nine months ended September 30, 2015 also included $10.1 million related to the impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases. Approximately $8.2 million of the total for the nine months ended September 30, 2015 is related to unproved lease cost amortization of the Elm Hill project in Fayette and Gonzales counties Texas. Impairment expense for the nine months ended September 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. Impairment expenses for the nine months ended September 30, 2014 also included a $7.1 million impairment and partial impairment of certain unproved prospects due to expiring leases and leases not likely to be drilled.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the nine months ended September 30, 2015 was approximately $112.3 million or $4.32 per Mcfe. This compares to approximately $114.9 million or $3.76 per Mcfe for the nine months ended September 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 nine months ended September 30, 2015 were approximately $22.7 million, compared to $26.5 million for the nine months ended September 30, 2014. General and administrative expenses for the nine months ended September 30, 2015 included approximately $5.0 million in non-cash stock based compensation, while the prior year included $3.3 million in non-cash stock based compensation. Also included in the current year was approximately $0.6 million in cash severance costs resulting from an August 2015 reduction in staff, and included in the prior year was approximately $2.6 million in merger related costs. Exclusive of the severance and merger related costs, cash general and administrative expenses for the current year were $17.1 million, compared to cash expenses of $20.6 million for the prior year. The reduction in force was a major step in our ongoing cost cutting efforts necessitated by the current challenging commodity price environment.

Loss/Gain from Affiliates

For the nine months ended September 30, 2015, the Company recorded a loss from affiliates of approximately $0.6 million, net of tax benefit of $0.3 million, related to our investment in Exaro, compared to a gain of $4.4 million, net of tax expense of $2.4 million, for the nine months ended September 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 September 30, 2015, we incurred $7.9 million for capital projects, including $1.2 million for final testing on two non-commercial wells in our Elm Hill Project in Fayette and Gonzales counties, $3.7 million on the two delineation wells on our North Cheyenne Project in Weston County, Wyoming and $4.3 million for the acquisition of leases and other rights in new areas.

During the nine months ended September 30, 2015, we incurred $51.6 million for capital projects, including $13.7 million on the Woodbine formation in our Madison and Grimes counties area, $12.3 million related to drilling on our Elm Hill Project in Fayette and Gonzales counties, $12.8 million in drilling costs on our FRAMS and North Cheyenne Projects in Wyoming and $11.5 million for the acquisition of leases and other rights in new areas.

Our capital expenditure budget for 2015 is currently forecasted to be approximately $58 million, including the amounts spent during the nine months ended September 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 $19.3 million in cash for the nine months ended September 30, 2015 compared to providing $176.8 million for the same period in 2014. The table below provides additional detail of cash flows from operating activities for the nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Cash flows from operating activities, exclusive of changes in working capital accounts	$ 45,753	$ 158,791
Changes in operating assets and liabilities	(26,503)	18,045
Net cash provided by operating activities	$ 19,250	$ 176,836

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 nine months ended September 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 nine months ended September 30, 2015, the working capital deficit normally associated with an active drilling program was reduced as we strategically planned our drilling activity to preserve our healthy balance sheet.

Cash From Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2015 were approximately $70.4 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 nine months ended September 30, 2014 were approximately $141.3 million, including a $146.7 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. Amounts presented for each period include cash payments in each period for accrued amounts at the beginning of each period.

Cash From Financing Activities

Cash flows provided by financing activities for the nine months ended September 30, 2015 were approximately $51.1 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 nine months ended September 30, 2014 were approximately $35.5 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. As part of the regular redetermination schedule, the borrowing base was redetermined at $225 million effective May 7, 2015 by the bank group due primarily to lower commodity prices and the impact of the significant reduction in the Company’s drilling program in 2015. The next regular scheduled redetermination is expected to be completed mid-November. Due to the lower commodity price environment and the reduced capital program, the Company expects some reduction in the borrowing base. Based on preliminary discussions with our agent bank and their borrowing base recommendation currently being considered by the remaining lenders under the facility, the Company expects that the proposed borrowing base will not impact our liquidity position in a material adverse way.

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 September 30, 2015, we were in compliance with all covenants under the RBC Credit Facility. As a condition to borrow funds or issue letters of credit under the RBC Credit Facility, we must remain in compliance with the restrictive covenants. We also must make certain representations and warranties to our bank lenders at the time of each borrowing, including representations about our solvency. If we do not meet our financial ratios or are unable to give the required representations, then we will need a waiver or amendment from our bank lenders in order to continue to be able to borrow or issue letters of credit under the RBC Credit Facility. Although we believe our bank lenders are well secured under the terms of the RBC Credit Facility, there is no assurance that the bank lenders would provide any waiver or amendment in the future should either become conditions to further lending. 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 September 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 September 30, 2015, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $2.9 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 September 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 September 30, 2015, we have 105 MBbl of crude oil production hedged between October 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 September 30, 2015, our total long-term debt was $114.6 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 September 30, 2015, our effective rates fluctuated between 1.9 percent and 4.3 percent, depending on the term of the specific debt drawdowns. At September 30, 2015, we did not have any outstanding interest rate swap agreements. As of September 30, 2015, the weighted average interest rate on our variable rate debt was 2.12% 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 $0.9 million for the nine month period.

Other Financial Instruments

As of September 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 September 30, 2015, an immediate 10% change in interest rates would result in a $0.2 million 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 September 30, 2015. Based upon that evaluation, the Company’s management concluded that, as of September 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 nine months ended September 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 our subsidiary would likely be responsible for at least one-half, and possibly as much as two-thirds, of the judgment if it stands. The Louisiana Supreme Court is currently reviewing this case, although there remains uncertainty whether the 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. The trial court entered judgment in favor of our subsidiary and the successors to the grantors under the aforementioned deeds, although indications are that the plaintiff will appeal the trial court's decision to the applicable state Court of Appeals. 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.

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: November 4, 2015	By:	/S/ ALLAN D. KEEL Allan D. Keel President and Chief Executive Officer (Principal Executive Officer)
Date: November 4, 2015	By:	/S/ E. JOSEPH GRADY E. Joseph Grady Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 4, 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.

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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.