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, 2016

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 AVENUE, SUITE 2900	77002

HOUSTON, TEXAS
(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, 2016 was 25,262,152.

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2016

TABLE OF CONTENTS

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

Table of Contents

Item 1. Consolidated Financial Statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	September 30, 2016 (unaudited)	December 31, 2015
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	10,629	20,504
Prepaid expenses	1,510	1,228
Inventory	540	540
Total current assets	12,679	22,272
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,194,990	1,187,707
Unproved properties	32,283	16,439
Other property and equipment	1,081	1,081
Accumulated depreciation, depletion and amortization	(874,827)	(826,022)
Total property, plant and equipment, net	353,527	379,205
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	16,024	14,222
Other	1,430	1,057
Total other non-current assets	17,454	15,279
TOTAL ASSETS	$ 383,660	$ 416,756
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 39,908	$ 36,358
Current derivative liability	2,133	—
Current asset retirement obligations	4,430	4,603
Total current liabilities	46,471	40,961
NON-CURRENT LIABILITIES:		
Long-term debt	62,463	115,446
Long-term derivative liability	267	—
Asset retirement obligations	23,004	22,506
Total non-current liabilities	85,734	137,952
Total liabilities	132,205	178,913
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 30,280,418 shares issued and 24,995,692 shares outstanding at September 30, 2016, 24,636,936	1,200	974

shares issued and 19,381,146 shares outstanding at December 31, 2015		
Additional paid-in capital	294,325	239,524
Treasury shares at cost (5,284,726 shares at September 30, 2016 and 5,255,790 shares at December 31, 2015)	(127,990)	(127,760)
Retained earnings	83,920	125,105
Total shareholders' equity	251,455	237,843
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 383,660	$ 416,756

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

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
REVENUES:				
Oil and condensate sales	$ 4,946	$ 9,500	$ 17,164	$ 35,882
Natural gas sales	12,011	16,020	31,283	48,130
Natural gas liquids sales	2,619	3,515	8,073	11,004
Total revenues	19,576	29,035	56,520	95,016
EXPENSES:				
Operating expenses	8,158	9,036	22,782	29,919
Exploration expenses	444	407	1,088	11,814
Depreciation, depletion and amortization	15,166	38,386	49,586	112,271
Impairment and abandonment of oil and gas properties	1,165	235,150	4,268	237,667
General and administrative expenses	7,486	7,504	18,772	22,683
Total expenses	32,419	290,483	96,496	414,354
OTHER INCOME (EXPENSE):				
Gain (loss) from investment in affiliates, net of income taxes	467	(375)	1,802	(562)
Interest expense	(989)	(785)	(3,045)	(2,315)
Gain on derivatives, net	913	2,011	736	2,001
Other income (expense)	18	4,288	(292)	5,278
Total other income (expense)	409	5,139	(799)	4,402
NET LOSS BEFORE INCOME TAXES	(12,434)	(256,309)	(40,775)	(314,936)
Income tax benefit (provision)	(51)	70,624	(410)	91,159
NET LOSS	$ (12,485)	$ (185,685)	$ (41,185)	$ (223,777)
NET LOSS PER SHARE:				
Basic	$ (0.55)	$ (9.79)	$ (2.02)	$ (11.81)
Diluted	$ (0.55)	$ (9.79)	$ (2.02)	$ (11.81)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	22,881	18,966	20,370	18,948
Diluted	22,881	18,966	20,370	18,948

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, 2016	2015
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (41,185)	$ (223,777)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	49,586	112,271
Impairment of natural gas and oil properties	4,137	237,656
Exploration expenses (recovery)	(2)	6,826
Deferred income taxes	—	(92,328)
Loss (gain) on sale of assets	(11)	231
Loss (gain) from investment in affiliates	(1,802)	865
Stock-based compensation	4,315	5,008
Unrealized loss (gain) on derivative instruments	2,400	(999)
Changes in operating assets and liabilities:		
Decrease in accounts receivable and other receivables	7,026	3,581
Increase in prepaid expenses	(282)	(5,198)
Decrease in accounts payable and advances from joint owners	(5,621)	(25,373)
Increase (decrease) in other accrued liabilities	2,384	(1,494)
Decrease in income taxes receivable, net	2,668	748
Other	(17)	1,233
Net cash provided by operating activities	$ 23,596	$ 19,250
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (19,849)	$ (70,389)
Sale of furniture & equipment	$ 11	$ —
Net cash used in investing activities	$ (19,838)	$ (70,389)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 118,310	$ 284,378
Repayments under credit facility	(171,293)	(233,168)
Net proceeds from equity offering	50,451	—
Purchase of treasury stock	(230)	(71)
Debt issuance costs	(996)	—
Net cash provided by (used in) financing activities	$ (3,758)	$ 51,139
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

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(in thousands, except number of shares)

	Common Stock		Additional Paid-in	Treasury	Retained	Total Shareholders'
	Shares	Amount	Capital	Stock	Earnings	Equity
	(unaudited)					
Balance at December 31, 2015	19,381,146	$ 974	$ 239,524	$ (127,760)	$ 125,105	$ 237,843
Equity offering	5,360,000	214	50,237	—	—	50,451
Treasury shares at cost	(28,936)	—	—	(230)	—	(230)
Restricted shares activity	283,482	12	(11)	—	—	1
Stock-based compensation	—	—	4,575	—	—	4,575
Net loss	—	—	—	—	(41,185)	(41,185)
Balance at September 30, 2016	24,995,692	$ 1,200	$ 294,325	$ (127,990)	$ 83,920	$ 251,455

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

Table of Contents

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 and offshore properties in the shallow waters of the Gulf of Mexico and to use that cash flow to explore, develop, exploit, produce and acquire crude oil and natural gas properties in the onshore Texas and Rocky Mountain regions of the United States.

The following table lists the Company’s primary producing areas as of September 30, 2016:

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
Weston County, Wyoming	Muddy Sandstone
Texas Gulf Coast	Conventional formations
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC (“Exaro”). Production associated with this investment is not included in the Company’s reported production results for the three and nine months ended September 30, 2016.

Since October 2013, upon the merger with Crimson Exploration Inc., the Company has focused its drilling efforts on liquids-rich horizontal resource plays, such as the Woodbine in Southeast Texas, the Eagle Ford and Buda in South Texas, and the Muddy Sandstone in Wyoming. In addition, the Company has (i) operated producing properties in the Haynesville Shale, Mid Bossier and James Lime formations in East Texas and (ii) operated producing properties in the Denver Julesburg Basin (“DJ Basin”) in Weld and Adams counties in Colorado, which the Company believes may also be prospective in the Niobrara Shale oil play. In July 2016, the Company purchased one-half of the seller’s interest in approximately 12,100 gross undeveloped acres (approximately 5,000 net acres) in the Southern Delaware Basin of Texas for up to $25 million. The Company commenced drilling of its first well on this recently acquired acreage in October 2016.

During the three months ended September 30, 2016, we completed an underwritten public offering of 5,360,000 shares of our common stock for net proceeds of approximately $50.5 million. See Note 3 - "Acquisition and Underwritten Public Offering" for additional information.

Due to the current challenging commodity price environment, the Company has been focusing its 2016 capital program on: (i) the preservation of its healthy financial position; (ii) identification of opportunities for cost efficiencies in all areas of its operations; and (iii) maintaining core leases and continuing to identify new resource potential opportunities internally and, where appropriate, through acquisition. The Company will continuously monitor the commodity price environment, and, if warranted, make adjustments to its strategy as the year progresses. As noted previously, the Company recently began drilling its first well in the newly acquired Southern Delaware Basin acreage.

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, 2015 (the "2015 Form 10-K") filed with the Securities and Exchange Commission ("SEC"). Please refer to the notes to the financial statements included in the 2015 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.

Table of Contents

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 2015 Form 10-K. The consolidated results of operations for the nine months ended September 30, 2016 are not necessarily indicative of the results that may be expected for the year ending December 31, 2016.

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. Republic Exploration LLC ("REX"), a partially-owned oil and gas exploration and development affiliate which is not controlled by the Company, was proportionately consolidated prior to its dissolution as of December 31, 2015. 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 cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows based on the Company's estimate of future reserves, natural gas and oil prices, operating costs and production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. The Company recognized no impairment of proved properties for the three months ended September 30, 2016 and approximately $0.7 million for impairment of proved properties for the nine months ended September 30, 2016. Substantially all of the non-cash impairment charge in the nine months ended September 30, 2016 was directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. The Company recognized $225.6 million impairment of proved properties for the three months ended September 30, 2015 and $227.6 million impairment of proved properties for the nine months ended September 30, 2015 also due to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves.

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 $1.1 million and approximately $3.4 million for the three and nine months ended September 30, 2016, respectively, related to partial impairment of unproved lease costs in non-core areas. 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.

Net Loss Per Common Share

Basic net loss per common share is computed by dividing the net loss attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net 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, 2016, 114,804 stock options and 437,355 restricted shares were excluded from dilutive shares due to the loss for the period. 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.

Table of Contents

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 the Company's current subsidiaries and any 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 August 2016, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update No. 2016-15: Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments. The main objective of this update is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This Update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The eight cash flow updates relate to the following issues: 1) debt prepayment or debt extinguishment costs; 2) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; 3) contingent consideration payments made after a business combination; 4) proceeds from the settlement of insurance claims; 5) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies; 6) distributions received from equity method investees; 7) beneficial interest in securitization transactions; and 8) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company will continue to assess the impact this may have on its statement of cash flows.

In May 2016, the FASB issued Accounting Standards Update No. 2016-12: Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients (ASU 2016-12). The core principle of the guidance in Topic 606 is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments of ASU 2016-12 do not change that core principle. Rather, the amendments affect only the following narrow aspects of Topic 606: assessing the collectability criterion and accounting for contracts that do not meet the criteria for step 1, presentation of sales tax and other similar taxes collected from customers, noncash consideration, contract modifications at transition, completed contracts at transition, and technical correction. For public entities, ASU 2016-12 is effective for annual reporting periods after December 31, 2017. 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 March 2016, the FASB issued Accounting Standards Update No. 2016-09: Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016 09 is part of an initiative to reduce complexity in accounting standards. The areas of simplification in ASU 2016 09 involve several aspects of accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public entities, ASU 2016-09 is effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years; early application is permitted. The provisions of this accounting update are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02: Leases (Topic 842) (ASU 2016-02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease

Table of Contents

liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize assets and liabilities arising from leases on the balance sheet. ASU 2016-02 further defines a lease as a contract that conveys the right to control the use of identified property, plant, or equipment for a period of time in exchange for consideration. Control over the use of the identified asset means that the customer has both (1) the right to obtain substantially all of the economic benefit from the use of the asset and (2) the right to direct the use of the asset. ASU 2016-02 requires disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company will continue to assess the impact this may have on its financial position, results of operations, and cash flows.

In January 2016, the FASB issued Accounting Standards Update No. 2016-01: Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities (ASU 2016-01). The main objective of ASU 2016-01 is enhancing the reporting model for financial instruments to provide users of financial statements with more decision-useful information. The amendments in ASU 2016-01 make targeted improvements to GAAP by: (i) requiring equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) be measured at fair value with changes in fair value recognized in net income; (ii) simplifying the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment; (iii) exempting all non-public business entities from disclosing fair value information for financial instruments measured at amortized cost; (iv) eliminating requirement for public business entities to disclose the methods and significant assumptions used to estimate the fair value for financial instruments measured at amortized cost on the balance sheet: (v) requiring public business entities to use the exit price notion when measuring the fair value of financial instruments for disclosure purposes; (vi) requiring separate presentation in other comprehensive income the portion of the total change in fair value of a liability resulting from a change in the instrument- specific credit risk when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments; (vii) requiring separate presentation of financial assets and financial liabilities by measurement category and form of financial asset; and (viii) clarifying that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity’s other deferred tax assets. For public entities, ASU 2016-01 is effective for financial statements issued for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years; 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.

Further, management is closely monitoring the joint standard-setting efforts of the FASB and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2016 and beyond. Because these pending standards have not yet been finalized, management is not able to determine the potential future impact that these standards will have, if any, on the Company's financial position, results of operations, or cash flows.

3. Acquisition and Underwritten Public Offering

In July 2016, the Company purchased one-half of the seller's interest in approximately 12,100 gross undeveloped acres (approximately 5,000 net acres) in the Southern Delaware Basin of Texas (the "Acquisition") for up to $25 million. The purchase price was comprised of $10 million in cash paid on July 26, 2016, and $10 million in carried well costs expected to be paid over the next 14 months. Certain additional payments contingent upon success could increase total consideration to $25 million.

During the three months ended September 30, 2016, the Company completed an underwritten public offering of 5,360,000 shares of its common stock for net proceeds of approximately $50.5 million. Proceeds from the offering were used to fund the portion of the purchase price paid at closing of the Acquisition and are expected to be used to fund drilling costs associated with the initial exploration and development of the acquired acreage. Pending such use, the Company used the proceeds of the offering to repay amounts outstanding under its revolving credit facility.

Table of Contents

4. 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, 2016. 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, 2016 (in thousands):

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$ —	$ —	$ —	$ —
Commodity price contracts - liabilities	$ 2,400	$ —	$ 2,400	$ —

Derivatives listed above are recorded in “Current and long-term derivative liability” on the Company’s consolidated balance sheet and include swaps and costless collars that are carried at fair value. The Company records the net change in the fair value of these positions in "Gain 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, 2015, there were no outstanding commodity price contracts. See Note 5 - "Derivative Instruments" for additional discussion of derivatives.

As of September 30, 2016, the Company's derivative contracts were with certain members of its bank group which are 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 six months. See Note 9 - "Long-Term Debt" for further information.

Impairments

Contango tests 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

Table of Contents

estimates or lower commodity prices. The Company estimates the undiscounted future cash flows expected in connection with the oil and gas properties on a field by field basis and compares such future cash flows to the unamortized capitalized costs of the properties. If the estimated future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. Because these significant fair value inputs are typically not observable, impairments of long-lived assets are classified as a Level 3 fair value measure.

Asset Retirement Obligations

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, estimated future plugging and abandonment costs and expected lives of the related reserves.

5. 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, 2016, the Company’s natural gas derivative positions consisted of “swaps” and “costless collars”. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a purchased put option and a sold call option, which establishes a minimum and maximum price, respectively, that the Company will receive for the volumes under the contract.

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 9 - "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 on derivatives, net" on the consolidated statements of operations.

Table of Contents

The following derivative instruments were in place at September 30, 2016 (fair value in thousands):

Commodity	Period	Derivative	Volume/Month	Price/Unit (1)	Fair Value
Natural Gas	Oct 2016	Swap	250,000 MMBtu	$ 2.53	(105)
Natural Gas	Nov 2016 - Dec 2016	Swap	1,300,000 MMBtu	$ 2.53	(1,270)
Natural Gas	Jan 2017 - Jul 2017	Collar	400,000 MMBtu	$ 2.65 - 3.00	(689)
Natural Gas	Aug 2017 - Oct 2017	Collar	200,000 MMBtu	$ 2.65 - 3.00	(106)
Natural Gas	Nov 2017 - Dec 2017	Collar	400,000 MMBtu	$ 2.65 - 3.00	(230)
		Total net fair value of derivative instruments			$ (2,400)

(1) Commodity price derivatives based on Henry Hub NYMEX natural gas prices.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of September 30, 2016 (in thousands):

	Gross	Netting (1)	Total
Assets	$ —	$ —	$ —
Liabilities	$ (2,400)	$ —	$ (2,400)

(1) Represents counterparty netting under agreements governing such derivatives.

As of December 31, 2015, the Company did not have any outstanding derivative positions.

The following table summarizes the effect of derivative contracts on the consolidated statements of operations for the three and nine months ended September 30, 2016 and 2015 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Crude oil contracts	$ —	$ 1,002	$ —	$ 1,002

Natural gas contracts	(619)	—	3,136	—
Realized gain (loss)	$ (619)	$ 1,002	$ 3,136	$ 1,002
Crude oil contracts	$ —	$ 1,009	$ —	$ 999
Natural gas contracts	1,532	—	(2,400)	—
Unrealized gain (loss)	$ 1,532	$ 1,009	$ (2,400)	$ 999
Gain on derivatives, net	$ 913	$ 2,011	$ 736	$ 2,001

6. Stock-Based Compensation

During the nine months ended September 30, 2016, the Company had a stock-based compensation program in effect 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"), which expired on February 25, 2015.

Effective September 1, 2015, all employees and board members entered into a salary replacement program (the "Salary Replacement Program"). The Salary Replacement Program reduced all office employees' base salary by 10% and all board of director retainer and committee chairman fees by 10% and replaced the portion of the salary/fees being reduced with immediately vested common stock in a number of shares commensurate with the salary/fees reduction amount. These shares were to be issued immediately after the year for which the salary was reduced. The Company discontinued this policy effective September 1, 2016 and the compensation accrued as of that date was paid to employees and directors in cash.

Table of Contents

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, 2016 and 2015, there was no excess tax benefit recognized.

Compensation expense related to stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. No stock options were granted during the nine months ended September 30, 2016 or 2015.

During the nine months ended September 30, 2016, no stock options were exercised and 1,657 stock options were forfeited. 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.

Restricted Stock

During the nine months ended September 30, 2016, the Company granted 40,876 shares of restricted common stock under the 2009 Plan for salaries replaced pursuant to the Salary Replacement Program for 2015. Of these, 38,943 shares were granted to employees, and 1,933 shares were granted to directors. Additionally, the Company granted 197,306 shares of restricted common stock to employees as part of their overall compensation package, which vest over four years, and 49,460 shares of restricted common stock to directors pursuant to the Company's director compensation plan, which vest after one year. The weighted average fair value of the restricted shares granted during the nine months ended September 30, 2016, was $11.60 with a total fair value of approximately $3.3 million after adjustment for an estimated weighted average forfeiture rate of 3.5%. During the nine months ended September 30, 2016, 4,160 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the nine months ended September 30, 2016 was approximately $130 thousand. No shares of restricted common stock were granted or forfeited during the three months ended September 30, 2016. Approximately 0.6 million shares remain available for grant under the 2009 Plan as of September 30, 2016.

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%. 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. No shares of restricted common stock were granted and 216 restricted shares were forfeited by former employees during the three months ended September 30, 2015.

The Company recognized approximately $4.3 million and $5.0 million in stock compensation expense during the nine months ended September 30, 2016 and 2015, respectively, for restricted shares granted to its officers, employees and directors. As of September 30, 2016, an additional $5.9 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 2.4 years.

In October 2016, two members of the Company’s management team had employment agreements that expired and were not renewed, resulting in the immediate vesting of 25,928 shares of unvested stock.

Table of Contents

7. 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, 2016		December 31, 2015	
Accounts receivable:				
Trade receivable	$	5,876	$	7,530
Alta Resources		1,993		1,993
Joint interest billing		3,120		7,366
Income taxes receivable		—		2,868
Other receivables		322		1,448
Allowance for doubtful accounts		(682)		(701)
Total accounts receivable	$	10,629	$	20,504
Prepaid expenses:				
Prepaid insurance	$	800	$	900
Other prepaids		710		328
Total prepaid expenses	$	1,510	$	1,228
Accounts payable and accrued liabilities:				
Royalties and revenue payable	$	17,299	$	17,906
Advances from partners		66		950
Accrued exploration and development		907		3,659
Accrued carried well costs		10,000		—
Trade payable		3,740		8,053
Accrued LOE & workover expense		2,457		2,159
Accrued G&A and legal expense		3,366		2,596
Other accounts payable and accrued liabilities		2,073		1,035
Total accounts payable and accrued liabilities	$	39,908	$	36,358

Included in the table below is supplemental information about certain cash and non-cash transactions during the nine months ended September 30, 2016 and 2015 (in thousands):

	Nine Months Ended September 30,			
	2016		2015	
Cash payments:				
Interest payments	$	2,935	$	2,231
Income tax payments (refunds)	$	(2,337)	$	100

Non-cash investing activities in the consolidated statements of cash flows:		
Increase (decrease) in accrued capital expenditures	$ 7,248	$ (19,411)

8. 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%. The Company did not make any contributions during the nine months ended September 30, 2016. As of September 30, 2016, the Company had invested approximately $46.9 million.

Table of Contents

The following table (in thousands) presents condensed balance sheet data for Exaro as of September 30, 2016 and December 31, 2015. The balance sheet data was derived from Exaro's balance sheet as of September 30, 2016 and December 31, 2015 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, 2016 was approximately $15.9 million.

	September 30, 2016	December 31, 2015
Current assets (1)	$ 19,303	$ 23,664
Non-current assets:		
Net property and equipment	93,440	101,459
Other non-current assets	1,157	486
Total non-current assets	94,597	101,945
Total assets	$ 113,900	$ 125,609
Current liabilities	$ 7,199	$ 5,272
Non-current liabilities:		
Long-term debt	59,228	78,500
Other non-current liabilities	3,646	2,891
Total non-current liabilities	62,874	81,391
Members' equity	43,827	38,946
Total liabilities & members' equity	$ 113,900	$ 125,609

(1) Approximately $15.5 million and $14.4 million of current assets as of September 30, 2016 and December 31, 2015, respectively, is cash.

The following table (in thousands) presents the condensed results of operations for Exaro for the three and nine months ended September 30, 2016 and 2015. The results of operations for the three and nine months ended September 30, 2016 and 2015 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, 2016 and 2015 was a gain of $0.5 million, net of no tax expense, and a loss of $0.4 million, net of tax benefit of $0.2 million, respectively. The Company's share in Exaro's results of operations recognized for the nine months ended September 30, 2016 and 2015 was a gain of $1.8 million, net of no tax expense, and a loss of $0.6 million, net of tax benefit of $0.3 million, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Production:				
Oil (thousand barrels)	30	40	98	127
Gas (million cubic feet)	2,659	3,236	8,083	9,928
Total (million cubic feet equivalent)	2,839	3,477	8,671	10,691

Oil and natural gas sales	$ 8,242	$ 7,881	$ 20,730	$ 31,731
Gain (loss) on derivatives	1,011	—	(1,231)	—
Other gain	—	3,667	10,441	3,608
Less:				
Lease operating expenses	3,969	4,467	11,513	12,946
Depreciation, depletion, amortization & accretion	2,880	7,229	8,705	20,147
General & administrative expense	671	724	2,605	2,586
Income (loss) from continuing operations	1,733	(872)	7,117	(340)
Net interest expense	(598)	(689)	(1,994)	(2,243)
Net income (loss)	$ 1,135	$ (1,561)	$ 5,123	$ (2,583)

Exaro's results of operations do not include income taxes because Exaro is treated as a partnership for tax purposes.

Table of Contents

9. 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. Effective October 28, 2016, as part of the regular redetermination schedule, the borrowing base under the RBC Credit Facility was reaffirmed at $140 million, which is unchanged from the redetermination amount on May 6, 2016. Also effective May 6, 2016, the RBC Credit Facility was amended to, among other things, extend the maturity of the facility from October 1, 2017 to October 1, 2019, increase the LIBOR, U.S. prime rate and federal funds rate margins to 2.5% - 4.0% and increase the commitment fee to 0.5%, regardless of the amount of the credit facility that is unused. The borrowing base under the facility is redetermined each November and May.

As of September 30, 2016 and December 31, 2015, the Company had approximately $62.5 million and $115.4 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, 2016, borrowing availability under the RBC Credit Facility was $75.6 million.

Total interest expense under the RBC Credit Facility, including commitment fees, for the three and nine months ended September 30, 2016 was approximately $1.0 million and $3.0 million, respectively. 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.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the RBC Credit Facility Agreement. As of September 30, 2016, the Company was in compliance with all financial covenants under the RBC Credit Facility, and at current commodity prices, does not expect any covenant compliance issues over the next twelve months. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at September 30, 2016 and December 31, 2015 was 3.9% and 2.4%, respectively. The RBC Credit Facility matures on October 1, 2019, at which time any outstanding balances will be due.

10. 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,	
	2016	2015	2016	2015
Current tax provision:				
Federal	$ —	$ —	$ —	$ —
State	51	(5)	410	517
Total	$ 51	$ (5)	$ 410	$ 517
Deferred tax benefit:				
Federal	$ —	$ (70,631)	$ —	$ (91,254)
State	—	(191)	—	(725)
Total	$ —	$ (70,822)	$ —	$ (91,979)
Total tax provision (benefit):				
Federal	$ —	$ (70,631)	$ —	$ (91,254)
State	51	(196)	410	(208)
Total	$ 51	$ (70,827)	$ 410	$ (91,462)
Included in gain from investment in affiliates	$ —	$ (203)	$ —	$ (303)
Total income tax provision (benefit)	$ 51	$ (70,624)	$ 410	$ (91,159)

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

Table of Contents

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, established a full valuation allowance at September 30, 2015. For the nine months ended September 30, 2016, the Company continues to fully value the net deferred tax asset. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

11. Related Party Transactions

Republic Exploration LLC

Historically, REX, an entity owned 32.3% by Contango, participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specified each participant's working interest, net revenue interest and described when such interests were earned. The Company proportionately consolidated the results of REX in its consolidated financial statements prior to REX's dissolution as of December 31, 2015.

Olympic Energy Partners

Mr. Joseph J. Romano, the Chairman of the Company's board of directors, is also the President and Chief Executive Officer of Olympic Energy Partners LLC ("Olympic"). Olympic last participated with the Company in the drilling of wells in March 2010, and its ownership in Company-operated wells is limited to our Dutch and Mary Rose wells.

During the three and nine months ended September 30, 2016, Mr. Romano earned $17 thousand and $43 thousand for his service as a director of the Company, respectively. During the three and nine months ended September 30, 2015, Mr. Romano earned $13 thousand and $66 thousand for his service as a director of the Company, respectively.

During the years ended December 31, 2015 and 2014, Mr. Romano received 4,534 and 2,612 shares of restricted stock, respectively, which both vest 100% on the one-year anniversary of the date of grant, as part of his board of director compensation. Additionally, in January 2016, Mr. Romano received 261 shares of restricted stock, pursuant to the Salary Replacement Program and an additional 9,892 shares of restricted stock in May 2016, which vest in one year, as part of his board of director compensation. The Company recognized compensation expense of approximately $30 thousand and $70 thousand related to the shares granted to Mr. Romano for the three and nine months ended September 30, 2016, respectively. During the three and nine months ended September 30, 2015, the Company recognized compensation expense of approximately $20 thousand and $82 thousand, respectively, related to the shares granted to Mr. Romano.

Below is a summary of payments received from (paid to) Olympic 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,			
	2016		2015	
	Olympic	REX	Olympic	REX
Revenue payments as well owners	$ (617)	$ —	$ (1,173)	$ (240)
Joint interest billing receipts	149	—	99	113

	Nine Months Ended September 30,			
	2016		2015	
	Olympic	REX	Olympic	REX
Revenue payments as well owners	$ (1,788)	$ —	$ (3,314)	$ (735)
Joint interest billing receipts	272	—	388	181

Table of Contents

As of September 30, 2016 and December 31, 2015, the Company's consolidated balance sheets reflected the following balances (in thousands):

	September 30, 2016		December 31, 2015	
	Olympic	REX	Olympic	REX
Accounts receivable:				
Joint interest billing	$ —	$ —	$ 26	$ 27
Accounts payable:				
Royalties and revenue payable	(502)	—	(451)	(83)

Oaktree Capital Management L.P.

As of September 30, 2016, Oaktree Capital Management L.P. ("Oaktree"), through various funds, owned approximately 5.2% of the Company's stock. On October 1, 2013, Mr. James Ford, then a Managing Director and Portfolio Manager within Oaktree, was elected to the Company's board of directors. Mr. Ford is currently a Senior Advisor to Oaktree.

Historically, all cash and equity awards payable to Mr. Ford were instead granted to an affiliate of Oaktree. During the years ended December 31, 2015 and 2014, an affiliate of Oaktree received 4,534 and 2,612 shares of restricted stock, respectively, which both vest 100% on the one-year anniversary of the date of the grant. Additionally, in January 2016, an affiliate of Oaktree received 313 shares of restricted stock, pursuant to the Salary Replacement Program and an additional 9,892 shares of restricted stock in May 2016, which vest in one year, as part of Mr. Ford’s board of director compensation. Beginning October 1, 2016, all cash and equity awards payable to Mr. Ford will be paid to him directly.

During the three and nine months ended September 30, 2016, the affiliate of Oaktree earned $18 thousand and $50 thousand in cash as a result of Mr. Ford's board participation, and the Company recognized compensation expense of approximately $30 thousand and $70 thousand related to the shares of restricted stock granted to an affiliate of Oaktree under the Director Compensation Plan, respectively. 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 granted to an affiliate of Oaktree under the Director Compensation Plan, respectively.

12. 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.

In July 2010, several parties associated with a limited partnership, formed to invest in oil and gas properties, that was dissolved in 1995 filed suit against a subsidiary of the Company and several co-defendants in district court for Madison County in Texas. The plaintiffs claim to own or have rights in certain oil and gas properties situated in Madison County, Texas by virtue of the partnership having interests in addition to those it held of record at the time of its dissolution, which were distributed to the partners in connection with such dissolution. A predecessor of the subsidiary of the Company involved in this case acquired a portion of the interests now claimed by the plaintiffs from a successor to the general partner of the aforementioned partnership in 2000. The plaintiffs' expert has provided a range of estimated monetary damages of up to approximately $9.4 million as to our Subsidiary. The Company is vigorously defending this lawsuit and believes that it has meritorious defenses.

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

Table of Contents

poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company is vigorously defending this lawsuit, believes that it has meritorious defenses and is appealing the trial court's decision to the applicable state Court of Appeals.

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

Mineral interest owners in South Louisiana filed suit against a subsidiary of the Company and several co-defendants in April 2013 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. This case is based on the same actions and allegations as a prior case in which the Company and its co-defendants prevailed. The plaintiffs claim damages of approximately $2.5 million against a subsidiary of the Company and its co-defendants. The Company and its co-defendants are vigorously defending this lawsuit and believe they have a meritorious position.

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.

Throughput Contract Commitment

The Company signed a throughput agreement with a third party pipeline owner/operator that constructed a line in our Southeast Texas area that allowed us to defray the cost of building a pipeline. The Company currently forecasts that, beginning in the fourth quarter of 2016, gas volume deliveries through this line in our Southeast Texas area will not meet minimum throughput requirements under the agreement. Without further development in that area, the volume deficiency will continue monthly through the expiration of the throughput commitment in March 2020. The throughput deficiency fee is paid in March of each calendar year. As of September 30, 2016, the Company estimates that the net deficiency fee will be in the range of $0.7 to $1.2 million annually for the remaining contract period, based upon forecasted production volumes from existing proved producing reserves only, assuming no future development during this commitment period. Based upon the current commodity price market and our short term strategic drilling plans, the Company recorded a loss contingency of $1.2 million at September 30, 2016. The Company will continue to assess this commitment in light of our drilling and development plans for this area.

Table of Contents

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 ability to successfully develop our recent acquisition of undeveloped acreage in the Southern Delaware Basin, integrate the operations relating thereto with our existing operations and realize the benefits of such acquisition;
- 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 operating 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;

Table of Contents

- 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
- our 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.

Table of Contents

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 2015 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 and offshore properties in the shallow waters of the Gulf of Mexico 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, 2016:

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
Weston County, Wyoming	Muddy Sandstone
Texas Gulf Coast	Conventional formations
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC ("Exaro"). Production associated with this investment is not included in our reported production results for the three and nine months ended September 30, 2016.

Since October 2013, upon the merger with Crimson Exploration Inc., the Company has focused its drilling efforts on liquids-rich horizontal resource plays, such as the Woodbine in Southeast Texas, the Eagle Ford and Buda in South Texas, and the Muddy Sandstone in Wyoming. In addition, the Company has (i) operated producing properties in the Haynesville Shale, Mid Bossier and James Lime formations in East Texas and (ii) operated producing properties in the Denver Julesburg Basin ("DJ Basin") in Weld and Adams counties in Colorado, which the Company believes may also be prospective in the Niobrara Shale oil play. In July 2016, the Company purchased one-half of the seller's interest in approximately 12,100 gross undeveloped acres (approximately 5,000 net acres) in the Southern Delaware Basin of Texas for up to $25 million. The Company commenced drilling of its first well on this recently acquired acreage in October 2016.

During the three months ended September 30, 2016, we completed an underwritten public offering of 5,360,000 shares of our common stock for net proceeds of approximately $50.5 million. See Note 3 - "Acquisition and Underwritten Public Offering" for additional information.

Due to the current challenging commodity price environment, the Company has been focusing its 2016 capital program on: (i) the preservation of our healthy financial position; (ii) identification of opportunities for cost efficiencies in all areas of our operations; and (iii) maintaining core leases and continuing to identify new resource potential opportunities internally and, where appropriate, through acquisition. We will continuously monitor the commodity price environment, stability and forecast, and, if warranted, make adjustments to our strategy as the year progresses. As noted previously, the Company recently began drilling its first well in the newly acquired Southern Delaware Basin acreage.

Capital Expenditures

Due to the low and uncertain commodity price environment, we initially limited our 2016 capital program to the completion of a well drilled in late 2015 and certain lease extensions in our core areas, thereby positioning us to repay a portion of our debt in the latter half of the year. As a result of our acreage acquisition in July, we will focus the remainder of 2016 capital expenditures on exploration of that newly acquired Southern Delaware Basin acreage. We currently forecast our net fourth quarter 2016 capital expenditures at $16.6 million.

Table of Contents

Southern Delaware Basin

On October 15, 2016, we spud our first well – the Lonestar Gunfighter 1813 #1H – in our newly acquired acreage in the Southern Delaware Basin, targeting the Upper Wolfcamp shale formation. Nearby operators have recently drilled in the Upper Wolfcamp and other areas targeting formations that we believe are prospective targets for our 12,100 gross (5,000 net) acre position. We have a 47.5% working interest in this initial well, and given success, expect to begin production in late December or early January.

Weston County, Wyoming

During the nine months ended September 30, 2016, we began producing from the Popham #1H well (80% WI) in Weston County, Wyoming, which is our second Muddy Sandstone formation well (referred to as our North Cheyenne Project) and the Christensen #1H (80% WI), our third well in this area. We do not have any further drilling plans for this area in 2017, as we will focus our efforts on higher rate of return projects, such as the Southern Delaware Basin.

Impairment of Long-Lived Assets

We recognized no impairment of proved properties during the three months ended September 30, 2016 and approximately $0.7 million in non-cash impairment charges of proved properties for the nine months ended September 30, 2016 primarily related to the reduction in the estimated value of future net cash flows of the Company's risk adjusted proved reserves due to low 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 proved, probable and possible reserves for that property. Also, we recognized an impairment charge for the three and nine months ended September 30, 2016 of approximately $1.1 million and $3.4 million, respectively, related to unproved lease cost amortization on our properties in Fayette and Gonzales counties Texas.

If oil and/or natural gas prices continue to decline, 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, 2016 was approximately 67% offshore and 33% onshore, and 71% natural gas, 12% oil and 17% natural gas liquids. Our production for the three months ended September 30, 2015 was 63% offshore and 37% onshore, and approximately 67% natural gas, 15% oil and 18% natural gas liquids.

The table below sets forth our average net daily production data in Mmcfe/d for each of our fields for each of the periods indicated:

	Three Months Ended				
	September 30, 2015	December 31, 2015	March 31, 2016	June 30, 2016	September 30, 2016
Offshore GOM					
Dutch and Mary Rose	49.5	48.6	45.9	43.3	39.3
Vermilion 170	7.0	6.9	6.5	6.2	4.0
Other offshore (1)	0.5	0.5	0.6	0.6	0.6
Southeast Texas (2)	22.9	20.1	16.4	13.9	12.1
South Texas (3)	8.9	8.1	7.4	7.4	7.5
Other (4)	2.1	2.5	2.6	3.2	2.2
	90.9	86.7	79.4	74.6	65.7

(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, Colorado, Wyoming and Tuscaloosa Marine Shale regions, among others.

Table of Contents

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 Canadian 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, 2016, Contaro had invested approximately $46.9 million in Exaro.

As of September 30, 2016, 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 31 Mmcfed, net to Exaro. Due to low natural gas prices, the operator does not expect to have any drilling rigs running on this project during the remainder of 2016. For the three months ended September 30, 2016 and 2015, we recognized a net investment gain of approximately $0.5 million, net of no tax expense, and a loss of approximately $0.4 million, net of tax benefit of $0.2 million, respectively, as a result of our investment in Exaro. For the nine months ended September 30, 2016 and 2015, we recognized a net investment gain of approximately $1.8 million, net of no tax expense, and a loss of approximately $0.6 million, net of tax benefit of $0.3 million, respectively. We do not anticipate making any additional equity contributions during 2016. See Note 8 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.

25

Table of Contents

Results of Operations for the Three and Nine Months Ended September 30, 2016 and 2015

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 operations for the three and nine months ended September 30, 2016 and 2015. 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,		
	2016	2015	%	2016	2015	%
Revenues (thousands):						
Oil and condensate sales	$ 4,946	$ 9,500	(48)%	$ 17,164	$ 35,882	(52)%
Natural gas sales	12,011	16,020	(25)%	31,283	48,130	(35)%
NGL sales	2,619	3,515	(25)%	8,073	11,004	(27)%
Total revenues	$ 19,576	$ 29,035	(33)%	$ 56,520	$ 95,016	(41)%
Production:						
Oil and condensate (thousand barrels)						
Offshore GOM	19	42	(55)%	106	149	(29)%
Southeast Texas	54	110	(51)%	190	400	(53)%
South Texas	28	47	(40)%	95	142	(33)%
Other	18	14	29 %	79	39	103 %
Total oil and condensate	119	213	(44)%	470	730	(36)%
Natural gas (million cubic feet)						
Offshore GOM	3,327	4,191	(21)%	10,841	13,117	(17)%
Southeast Texas	469	869	(46)%	1,666	2,342	(29)%
South Texas	407	420	(3) %	1,137	1,384	(18)%
Other	92	100	(8) %	245	317	(23)%
Total natural gas	4,295	5,580	(23)%	13,889	17,160	(19)%
Natural gas liquids (thousand barrels)						
Offshore GOM	99	133	(26)%	323	392	(18)%
Southeast Texas	53	96	(45)%	176	276	(36)%
South Texas	19	19	— %	55	67	(18)%
Other	2	2	— %	6	5	20 %
Total natural gas liquids	173	250	(31)%	560	740	(24)%
Total (million cubic feet equivalent)						
Offshore GOM	4,035	5,244	(23)%	13,415	16,367	(18)%
Southeast Texas	1,113	2,105	(47)%	3,866	6,401	(40)%
South Texas	689	816	(16)%	2,035	2,636	(23)%
Other	210	194	8 %	750	578	30 %
Total production	6,047	8,359	(28)%	20,066	25,982	(23)%
Daily Production:						
Oil and condensate (thousand barrels per day)						

Offshore GOM	0.2	0.4	(55)%	0.4	0.5	(29)%
Southeast Texas	0.6	1.2	(51)%	0.7	1.5	(53)%
South Texas	0.3	0.5	(40)%	0.3	0.5	(33)%
Other	0.2	0.2	29 %	0.3	0.2	103 %
Total oil and condensate	1.3	2.3	(44)%	1.7	2.7	(36)%
Natural gas (million cubic feet per day)						
Offshore GOM	36.2	45.6	(21)%	39.5	48.0	(17)%
Southeast Texas	5.1	9.4	(46)%	6.1	8.6	(29)%
South Texas	4.4	4.6	(3) %	4.1	5.1	(18)%
Other	1.0	1.1	(8) %	0.9	1.2	(23)%
Total natural gas	46.7	60.7	(23)%	50.6	62.9	(19)%

	Three Months Ended September 30, 2016	2015	%	Nine Months Ended September 30, 2016	2015	%
Natural gas liquids (thousand barrels per day)						
Offshore GOM	1.1	1.5	(26) %	1.2	1.5	(18) %
Southeast Texas	0.6	1.0	(45) %	0.6	1.0	(36) %
South Texas	0.2	0.2	— %	0.2	0.2	(18) %
Other	—	—	— %	—	—	20 %
Total natural gas liquids	1.9	2.7	(31) %	2.0	2.7	(24) %
Total (million cubic feet equivalent per day)						
Offshore GOM	43.9	57.0	(23) %	48.9	60.0	(18) %
Southeast Texas	12.1	22.9	(47) %	14.1	23.4	(40) %
South Texas	7.5	8.9	(16) %	7.4	9.7	(23) %
Other	2.2	2.1	8 %	2.8	2.1	30 %
Total production	65.7	90.9	(28) %	73.2	95.2	(23) %
Average Sales Price:						
Oil and condensate (per barrel)	$ 41.63	$ 44.56	(7) %	$ 36.49	$ 49.14	(26) %
Natural gas (per thousand cubic feet)	$ 2.80	$ 2.87	(2) %	$ 2.25	$ 2.80	(20) %
Natural gas liquids (per barrel)	$ 15.10	$ 14.05	7 %	$ 14.40	$ 14.86	(3) %
Total (per thousand cubic feet equivalent)	$ 3.24	$ 3.47	(7) %	$ 2.82	$ 3.66	(23) %
Expenses (thousands):						
Operating expenses	$ 8,158	$ 9,036	(10) %	$ 22,782	$ 29,919	(24) %
Exploration expenses	$ 444	$ 407	9 %	$ 1,088	$ 11,814	(91) %
Depreciation, depletion and amortization	$ 15,166	$ 38,386	(60) %	$ 49,586	$ 112,271	(56) %
Impairment and abandonment of oil and gas properties	$ 1,165	$ 235,150	(100)%	$ 4,268	$ 237,667	(98) %
General and administrative expenses	$ 7,486	$ 7,504	(0) %	$ 18,772	$ 22,683	(17) %
Gain from investment in affiliates (net of taxes)	$ 467	$ (375)	(225)%	$ 1,802	$ (562)	(421)%
Selected data per Mcfe:						
Operating expenses	$ 1.35	$ 1.08	25 %	$ 1.14	$ 1.15	(1) %
General and administrative expenses	$ 1.24	$ 0.90	38 %	$ 0.94	$ 0.87	8 %
Depreciation, depletion and amortization	$ 2.51	$ 4.59	(45) %	$ 2.47	$ 4.32	(43) %

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

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 changes in commodity prices, each of 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 $19.6 million for the three months ended September 30, 2016, compared to revenues of $29.0 million for the three months ended September 30, 2015. The decrease in revenues was primarily attributable to: (i) approximately $9.0 million due to lower production volumes resulting from a commodity price related reduction in drilling and (ii) a decline in commodity prices, which contributed approximately $0.4 million of the decrease in revenues.

Total equivalent production was 65.7 Mmcfed for the three months ended September 30, 2016, compared to 90.9 Mmcfed in the prior year quarter, a decrease attributable primarily to a 10.2 Mmcfed decline in production from the Dutch and Mary Rose Field as a result of typical field decline and a 12.1 Mmcfed decline in onshore production related to the strategic decrease in our capital program during 2016 due to the low, and uncertain, commodity price environment.

Table of Contents

Average Sales Prices

The average equivalent sales price realized for the three months ended September 30, 2016 was $3.24 per Mcfe compared to $3.47 per Mcfe for the three months ended September 30, 2015. This decrease was attributable primarily to the decrease in the realized price of oil to $41.63 per barrel, compared to $44.56 per barrel for the three months ended September 30, 2015, and to the decrease in the realized price of natural gas to $2.80 per Mcf, compared to $2.87 per Mcf for the three months ended September 30, 2015.

Operating Expenses

Operating expenses for the three months ended September 30, 2016 were approximately $8.2 million, or $1.35 per Mcfe, compared to $9.0 million, or $1.08 per Mcfe, for the three months ended September 30, 2015. The table below provides additional detail of operating expenses for the three months ended September 30, 2016 and 2015:

	Three Months Ended September 30,			
	2016		2015	
	(in thousands)	($ per Mcfe)	(in thousands)	($ per Mcfe)
Lease operating expenses	$ 4,580	0.76	$ 5,864	$ 0.70
Production & ad valorem taxes	755	0.12	814	0.10
Transportation & processing costs	2,188	0.36	1,270	0.15
Workover costs	635	0.11	1,088	0.13
Total operating expenses	$ 8,158	1.35	$ 9,036	$ 1.08

Lease operating expenses decreased by 22% for the three months ended September 30, 2016, compared to the three months ended September 30, 2015, as a direct result of our efforts to reduce costs during this challenging commodity price environment.

Transportation & processing costs increased by 72% for the three months ended September 30, 2016, compared to the three months ended September 30, 2015, as a result of an accrual loss contingency of $1.2 million related to a throughput agreement with a third party pipeline operator.

Exploration Expenses

Exploration expenses for the three months ended September 30, 2016 were approximately $0.4 million, comparable to the prior year quarter.

Impairment Expenses

Impairment expenses for the three months ended September 30, 2016 included a $1.1 million impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases related to properties in Fayette and Gonzales counties Texas.

Impairment expense for the three months ended September 30, 2015 included proved property impairments of $225.6 million. Approximately $196.5 million of the total proved property impairment for the three months ended September 30, 2015 was attributable to Southeast Texas and South Texas properties. Impairment expense for the three months ended September 30, 2015 also 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 was related to unproved lease cost amortization of properties in Fayette and Gonzales counties Texas.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended September 30, 2016 was approximately $15.2 million, or $2.51 per Mcfe. This compares to approximately $38.4 million, or $4.59 per Mcfe, for the three months

Table of Contents

ended September 30, 2015. The decrease in the depletion rate for 2016 is primarily attributable to the impairment expense recorded in 2015.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2016 were approximately $7.5 million, compared to $7.5 million for the three months ended September 30, 2015. The current year quarter includes a $1.5 million increase in the cumulative bonus accrual compared to the previous year and $0.5 million related to the discontinuance of the Salary Deferral Program initiated in late 2015. General and administrative expenses included approximately $1.3 million and $2.4 million in non-cash stock based compensation, for the current and prior year quarters, respectively.

Gain (loss) from Affiliates

For the three months ended September 30, 2016, the Company recorded a gain from affiliates of approximately $0.5 million, net of no tax expense, related to our investment in Exaro, compared to a loss of $0.4 million, net of tax benefit of $0.2 million, for the three months ended September 30, 2015.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

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 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 $56.5 million for the nine months ended September 30, 2016, compared to revenues of $95.0 million for the nine months ended September 30, 2015. The decrease in revenues was primarily attributable to: (i) a $13.9 million decline attributable to the significant drop in commodity prices and (ii) $24.6 million decline due to lower production volumes resulting from the reduction in drilling.

Total equivalent production declined from 95.2 Mmcfed during the nine months ended September 30, 2015 to 73.2 Mmcfed for the nine months ended September 30, 2016, a decrease attributable primarily to typical field decline (approximately 11.1 Mmcfed) in our Gulf of Mexico production and a 9.3 Mmcfed decline in Southeast Texas production due to the price-related strategic decrease in our capital program during 2016.

Average Sales Prices

The average equivalent sales price realized for the nine months ended September 30, 2016 was $2.82 compared to $3.66 for the nine months ended September 30, 2015. This decrease was attributable primarily to the decrease in the realized price of oil to $36.49 per barrel, compared to $49.14 per barrel for the nine months ended September 30, 2015, and to the decrease in the realized price of natural gas to $2.25 per Mcf, compared to $2.80 per Mcf for the nine months ended September 30, 2015.

Table of Contents

Operating Expenses

Operating expenses for the nine months ended September 30, 2016 were approximately $22.8 million, or $1.14 per Mcfe, compared to $29.9 million, or $1.15 per Mcfe, for the nine months ended September 30, 2015. The table below provides additional detail of operating expenses for the nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30,			
	2016		2015	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 14,487	$ 0.72	$ 19,484	$ 0.75
Production & ad valorem taxes	2,809	0.14	3,751	0.14
Transportation & processing costs	4,397	0.23	3,891	0.15
Workover costs	1,089	0.05	2,793	0.11
Total operating expenses	$ 22,782	1.14	$ 29,919	$ 1.15

Lease operating expenses decreased by 26% for the nine months ended September 30, 2016, compared to the nine months ended September 30, 2015, as a direct result of our efforts to reduce costs during this challenging commodity price environment.

Transportation & processing costs increased by 13% for the nine months ended September 30, 2016, compared to the nine months ended September 30, 2015, as a result of an accrual loss contingency of $1.2 million related to a throughput agreement with a third party pipeline operator.

Exploration Expenses

Exploration expenses for the nine months ended September 30, 2016 were approximately $1.1 million. 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 the State #1H prospect which was drilled to test the Mowry shale formation in Natrona County, Wyoming and $3.2 million related to the early termination of a drilling rig contract.

Impairment Expenses

Impairment expenses for the nine months ended September 30, 2016 included a $0.7 million impairment of proved properties. Substantially all of the non-cash impairment charge in the current period is directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Impairment expenses for the nine months ended September 30, 2016 also included a $3.4 million impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases related to properties in Fayette and Gonzales counties Texas.

Impairment expense for the nine months ended September 30, 2015 included proved property impairments of $227.6 million. Approximately $196.5 million of the total proved property impairment for the nine months ended September

30, 2015 was attributable to Southeast Texas and South Texas properties. Impairment expense for the nine months ended September 30, 2015 also included a $10.1 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 impairment expense for the nine months ended September 30, 2015 was related to unproved lease cost amortization of the Elm Hill project in Fayette and Gonzales counties Texas.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the nine months ended September 30, 2016 was approximately $49.6 million or $2.47 per Mcfe. This compares to approximately $112.3 million or $4.32 per Mcfe for the nine months ended September 30, 2015. The decrease in the depletion rate for 2016 is primarily attributable to the impairment recorded during 2015.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2016 were approximately $18.8 million, compared to $22.7 million for the nine months ended September 30, 2015. This decrease is primarily a result of lower salaries of $2.7 million and other cost reductions implemented in late 2015 and 2016 and a $0.7 million decrease in stock based compensation compared to the previous year, offset in part by a current quarter change of $1.5 million related to a cumulative bonus accrual for 2016 and $0.5 million related to the discontinuance of the Salary Replacement Program. General and administrative expenses for the current year included approximately $4.3 million in non-cash stock based compensation, while the prior year included $5.0 million in non-cash stock based compensation.

Gain (loss) from Affiliates

For the nine months ended September 30, 2016, the Company recorded a gain from affiliates of approximately $1.8 million, net of no tax expense, related to our investment in Exaro, compared to a loss of approximately $0.6 million, net of tax benefit of $0.3 million, for the nine months ended September 30, 2015.

Capital Resources and Liquidity

During the nine months ended September 30, 2016, we incurred $26.5 million on capital projects, including $20.5 million in paid and accrued leasehold acquisition costs in the Southern Delaware Basin, $2.8 million for the completion of our third delineation well on our North Cheyenne Project in Weston County, Wyoming and $2.8 million for the extension and renewal of leases and other rights in other areas.

Our capital expenditure budget for 2016 was originally forecasted to be less than $10 million. As a result of our recent acquisition of Southern Delaware Basin acreage in July 2016, we have revised our 2016 budget to include an additional $20.5 million in previously mentioned leasehold acquisition and carried well costs and an additional $16.6 million in drilling and completion costs in the fourth quarter.

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 $23.6 million in cash for the nine months ended September 30, 2016 compared to $19.3 million provided by operating activities for the same period in 2015. The table below provides additional detail of cash flows from operating activities for the nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30,	
	2016	2015
	(in thousands)	
Cash flows from operating activities, exclusive of changes in working capital accounts	$ 17,438	$ 45,753
Changes in operating assets and liabilities	6,158	(26,503)
Net cash provided by operating activities	$ 23,596	$ 19,250

Production from our wells, the price of oil and natural gas, and operating costs represent the main drivers behind our cash flow from operations. Changes in working capital impact cash flows, and during the nine months ended September 30, 2016, the working capital deficit normally associated with an active drilling program was reduced as we strategically lowered 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, 2016 were approximately $19.8 million, all of which was used for capital expenditures related to drilling and/or completing wells and acquiring unproved leases in our areas of focus. Cash flows used in investing activities for the nine months ended September 30, 2015 were approximately $70.4 million, including $58.9 million which was used for capital expenditures related to drilling and/or completing wells and $11.5 million related to acquiring unproved leases in our areas of focus. Amounts presented include cash payments for accrued amounts at the beginning of each period.

Table of Contents

Cash From Financing Activities

Cash flows used in financing activities for the nine months ended September 30, 2016 were approximately $3.8 million, primarily related to the $53.0 million repayment of net borrowings under our credit facility with the Royal Bank of Canada and other lenders (the "RBC Credit Facility") offset by $50.5 million received in our equity offering. 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 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. Effective October 28, 2016, as part of the regular redetermination schedule, the borrowing base under the RBC Credit Facility was redetermined at $140 million, which is unchanged from the redetermination on May 6, 2016. Also effective May 6, 2016, the RBC Credit Facility was amended to, among other things, extend the maturity of the facility from October 1, 2017 to October 1, 2019, increase the LIBOR, U.S. prime rate and federal funds rate margins to 2.5% - 4.0% and increase the commitment fee to 0.5%, regardless of the amount of the credit facility that is unused.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the RBC Credit Facility Agreement. As of September 30, 2016, we were in compliance with all covenants under the RBC Credit Facility, and at current commodity prices, do not expect any covenant compliance issues over the next twelve months. 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.

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 2015 Form 10-K.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements, see Note 2 to our Financial Statements – "Summary of Significant Accounting 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, 2016, 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 2015 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 nine months

Table of Contents

ended September 30, 2016, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $2.0 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, 2016, 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 5 to our Financial Statements - "Derivative Instruments" for more details. As of September 30, 2016, we have 2,850,000 MMBtu of natural gas production hedged from October 2016 through December 2016 at an average Henry Hub price of $2.53/MMBtu. Also, as of September 30, 2016, we have 4,200,000 MMBtus of natural gas production hedged from January 2017 through December 2017 through collars at a floor price of $2.65/MMBtu.

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, 2016, our total long-term debt was $62.5 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 nine months ended September 30, 2016, our effective rates fluctuated between 2.3 percent and 6.8 percent, depending on the term of the specific debt drawdowns. At September 30, 2016, we did not have any outstanding interest rate swap agreements. As of September 30, 2016, the weighted average interest rate on our variable rate debt was 3.87% 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 $0.5 million for the nine month period.

Table of Contents

Other Financial Instruments

As of September 30, 2016, 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, 2016, 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, 2016. Based upon that evaluation, the Company’s management concluded that, as of September 30, 2016, 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 three months ended September 30, 2016 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

For a discussion of legal proceedings, see Note 12 to our Financial Statements – “Commitments and Contingencies.”

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A of Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2015, other than the following:

In connection with the Acquisition, we entered into a new area of exploration and development in which we have limited experience and facilities, and as a result we may experience inefficiencies, incur unanticipated or higher costs and expenses, or may not fully realize the benefits anticipated as a result of the Acquisition.

We have not historically operated in West Texas. As a result of the Acquisition, we will need to integrate the properties and operations relating thereto with our current oil and gas operations, which may increase the risk of inefficiencies in timing, coordination and staffing, unanticipated higher costs and expenses than we currently have projected or drilling results below our expectations. As a result, any desired benefits of the Acquisition may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

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

None.

Table of Contents

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.

Table of Contents

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 3, 2016	By:	/S/ ALLAN D. KEEL Allan D. Keel President and Chief Executive Officer (Principal Executive Officer)
Date: November 3, 2016	By:	/S/ E. JOSEPH GRADY E. Joseph Grady Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 3, 2016	By:	/S/ DENISE DUBARD Denise DuBard Chief Accounting Officer and Controller (Principal Accounting Officer)

Table of Contents

Exhibit Number	Description
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. (3)
10.1	Third Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signature Hereto. (4)
10.2	Amendment and Extension of Employee Agreement dated as of October 10, 2016 among Contango Oil & Gas Company and Allan D. Keel. (5)
10.3	Amendment and Extension of Employee Agreement dated as of October 10, 2016 among Contango Oil & Gas Company and E. Joseph Grady. (5)
10.4	Amendment and Extension of Employee Agreement dated as of October 10, 2016 among Contango Oil & Gas Company and A. Carl Isaac. (5)
10.5	Amendment and Extension of Employee Agreement dated as of October 10, 2016 among Contango Oil & Gas Company and Jay S. Mengle. (5)
10.6	Amendment and Extension of Employee Agreement dated as of October 10, 2016 among Contango Oil & Gas Company and Thomas H. Atkins. (5)
10.7	Form of Contango Oil and Gas Company Stock Award Agreement (employees) †
10.8	Form of Contango Oil and Gas Company Stock Award Agreement (executives) †
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.

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 September 30, 2002, as filed with the Securities and Exchange Commission on November 14, 2002.

3. 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.

4. Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, as filed with the Securities and Exchange Commission on May 9, 2016.

5. Filed as an exhibit to the Company's Current Report on Form 8-K dated October 14, 2016, as filed with the Securities and Exchange Commission on October 14, 2016.