# 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, 2017**

**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<br>HOUSTON, TEXAS** | **77002** |
| **(Address of principal executive offices)** | **(Zip Code)** |

**(713) 236-7400**
**(Registrant's telephone number, including area code)**

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

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

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

| | | | |
|---|---|---|---|
| Large accelerated filer | ☐ | Accelerated filer | ☒ |
| Non-accelerated filer | ☐ | Smaller reporting company | ☐ |
| Emerging growth company | ☐ | | |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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 6, 2017 was 25,509,792.

**CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES**
**QUARTERLY REPORT ON FORM 10-Q**
**FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2017**

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

**Item 1.** ***Consolidated Financial Statements***

**CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS**
**(in thousands, except shares)**

| | September 30, 2017 | December 31, 2016 |
|---|---|---|
| | (unaudited) | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ — | $ — |
| Accounts receivable, net | 11,757 | 16,727 |
| Prepaid expenses | 1,786 | 1,787 |
| Current derivative asset | 440 | — |
| Inventory | — | 540 |
| Total current assets | 13,983 | 19,054 |
| PROPERTY, PLANT AND EQUIPMENT: | | |
| Natural gas and oil properties, successful efforts method of accounting: | | |
| Proved properties | 1,221,391 | 1,188,065 |
| Unproved properties | 38,720 | 38,338 |
| Other property and equipment | 1,272 | 1,265 |
| Accumulated depreciation, depletion and amortization | (918,768) | (887,286) |
| Total property, plant and equipment, net | 342,615 | 340,382 |
| OTHER NON-CURRENT ASSETS: | | |
| Investments in affiliates | 18,242 | 15,767 |
| Other | 954 | 1,311 |
| Total other non-current assets | 19,196 | 17,078 |
| TOTAL ASSETS | $ 375,794 | $ 376,514 |
| | | |
| CURRENT LIABILITIES: | | |
| Accounts payable and accrued liabilities | $ 45,401 | $ 55,135 |
| Current derivative liability | 90 | 3,446 |
| Current asset retirement obligations | 4,008 | 4,308 |
| Total current liabilities | 49,499 | 62,889 |
| NON-CURRENT LIABILITIES: | | |
| Long-term debt | 79,226 | 54,354 |
| Asset retirement obligations | 18,082 | 22,618 |
| Other long term liabilities | 248 | 248 |
| Total non-current liabilities | 97,556 | 77,220 |
| Total liabilities | 147,055 | 140,109 |
| COMMITMENTS AND CONTINGENCIES (NOTE 12) | | |
| SHAREHOLDERS' EQUITY: | | |
| Common stock, $0.04 par value, 50 million shares authorized, 30,887,073 shares issued and 25,544,705 shares outstanding at September 30, 2017, 30,557,987 shares issued and 25,238,600 shares outstanding at December 31, 2016 | 1,224 | 1,211 |
| Additional paid-in capital | 300,986 | 296,439 |
| Treasury shares at cost (5,342,368 shares at September 30, 2017 and 5,319,387 shares at December 31, 2016) | (128,482) | (128,321) |
| Retained earnings | 55,011 | 67,076 |
| Total shareholders' equity | 228,739 | 236,405 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | $ 375,794 | $ 376,514 |

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

**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, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| | (unaudited) | | (unaudited) | |
| REVENUES: | | | | |
| Oil and condensate sales | $ 6,109 | $ 4,946 | $ 18,134 | $ 17,164 |
| Natural gas sales | 9,681 | 12,011 | 31,956 | 31,283 |
| Natural gas liquids sales | 3,040 | 2,619 | 8,440 | 8,073 |
| Total revenues | 18,830 | 19,576 | 58,530 | 56,520 |
| EXPENSES: | | | | |
| Operating expenses | 7,041 | 8,158 | 20,203 | 22,782 |
| Exploration expenses | 315 | 444 | 690 | 1,088 |
| Depreciation, depletion and amortization | 11,193 | 15,166 | 35,678 | 49,586 |
| Impairment and abandonment of oil and gas properties | 84 | 1,165 | 1,515 | 4,268 |
| General and administrative expenses | 6,219 | 7,486 | 18,648 | 18,772 |
| Total expenses | 24,852 | 32,419 | 76,734 | 96,496 |
| OTHER INCOME (EXPENSE): | | | | |
| Gain from investment in affiliates, net of income taxes | 525 | 467 | 2,475 | 1,802 |
| Gain (loss) from sale of assets | (184) | 11 | 2,336 | 11 |
| Interest expense | (1,138) | (989) | (2,822) | (3,045) |
| Gain (loss) on derivatives, net | (9) | 913 | 4,574 | 736 |
| Other income (expense) | — | 7 | (27) | (303) |
| Total other income (expense) | (806) | 409 | 6,536 | (799) |
| NET LOSS BEFORE INCOME TAXES | (6,828) | (12,434) | (11,668) | (40,775) |
| Income tax provision | (88) | (51) | (397) | (410) |
| NET LOSS | $ (6,916) | $ (12,485) | $ (12,065) | $ (41,185) |
| NET LOSS PER SHARE: | | | | |
| Basic | $ (0.28) | $ (0.55) | $ (0.49) | $ (2.02) |
| Diluted | $ (0.28) | $ (0.55) | $ (0.49) | $ (2.02) |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING: | | | | |
| Basic | 24,708 | 22,881 | 24,662 | 20,370 |
| Diluted | 24,708 | 22,881 | 24,662 | 20,370 |

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, 2017 | Nine Months Ended September 30, 2016 |
|---|---|---|
| | (unaudited) | |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net loss | $ (12,065) | $ (41,185) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 35,678 | 49,586 |
| Impairment of natural gas and oil properties | 1,400 | 4,137 |
| Exploration recovery | (232) | (2) |
| Gain on sale of assets | (2,336) | (11) |
| Gain from investment in affiliates | (2,475) | (1,802) |
| Stock-based compensation | 4,560 | 4,315 |
| Unrealized loss (gain) on derivative instruments | (3,797) | 2,400 |
| Changes in operating assets and liabilities: | | |
| Decrease in accounts receivable & other receivables | 4,767 | 7,026 |
| Decrease (increase) in prepaids | 1 | (282) |
| Decrease in inventory | 123 | — |
| Decrease in accounts payable & advances from joint owners | (1,744) | (5,621) |
| Increase in other accrued liabilities | 2,461 | 2,384 |
| Decrease in income taxes receivable, net | — | 2,868 |
| Decrease in income taxes payable, net | (308) | (200) |
| Other | 72 | (17) |
| Net cash provided by operating activities | $ 26,105 | $ 23,596 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Natural gas and oil exploration and development expenditures | $ (51,937) | $ (19,849) |
| Additions to furniture & equipment | (42) | — |
| Sale of furniture & equipment | 12 | 11 |
| Sale of oil & gas properties | 1,151 | — |
| Net cash used in investing activities | $ (50,816) | $ (19,838) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Borrowings under credit facility | $ 172,015 | $ 118,310 |
| Repayments under credit facility | (147,143) | (171,293) |
| Net proceeds from equity offering | — | 50,451 |
| Purchase of treasury stock | (161) | (230) |
| Debt issuance costs | — | (996) |
| Net cash provided by (used in) financing activities | $ 24,711 | $ (3,758) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | $ — | $ — |
| CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD | — | — |
| CASH AND CASH EQUIVALENTS, END OF PERIOD | $ — | $ — |

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

**CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY**
**(in thousands, except number of shares)**

| | Common Stock | | Additional Paid-in Capital | Treasury Stock | Retained Earnings | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| | Shares | Amount | | | | |
| | | | (unaudited) | | | |
| Balance at December 31, 2016 | 25,238,600 | $ 1,211 | $ 296,439 | $ (128,321) | $ 67,076 | $ 236,405 |
| Treasury shares at cost | (22,981) | — | — | (161) | — | (161) |
| Restricted shares activity | 329,086 | 13 | (13) | — | — | — |
| Stock-based compensation | — | — | 4,560 | — | — | 4,560 |
| Net income | — | — | — | — | (12,065) | (12,065) |
| Balance at September 30, 2017 | 25,544,705 | $ 1,224 | $ 300,986 | $ (128,482) | $ 55,011 | $ 228,739 |

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

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

## 1. Organization and Business

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

The following table lists the Company’s primary producing areas as of September 30, 2017:

| Location | Formation |
|---|---|
| Gulf of Mexico | Offshore Louisiana - water depths less than 300 feet |
| Madison and Grimes counties, Texas | Woodbine (Upper Lewisville) |
| Pecos County, Texas | Southern Delaware Basin (Wolfcamp) |
| Texas Gulf Coast | Conventional and unconventional formations |
| Zavala and Dimmit counties, Texas | Buda / Austin Chalk |
| Weston County, Wyoming | Muddy Sandstone |
| 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, 2017.

In July 2016, the Company purchased approximately 12,100 gross operated undeveloped acres (5,000 net acres) in the Southern Delaware Basin in Pecos County, Texas, which it began drilling during the fourth quarter of 2016, and as of September 30, 2017, had increased its acreage to approximately 13,600 gross operated acres (6,800 net).

The Company’s 2017 capital program has focused, and will continue to focus, on the development of the Company’s Southern Delaware Basin acreage. Additionally, the Company will continue to identify opportunities for cost efficiencies in all areas of its operations, maintain core leases and identify new resource potential opportunities internally and, where appropriate, through acquisition. The Company will continuously monitor the commodity price environment, including its stability and forecast, and, if warranted, make adjustments to its strategy as the year progresses.

## 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, 2016 (the “2016 Form 10-K”) filed with the Securities and Exchange Commission (“SEC”). Please refer to the notes to the financial statements included in the 2016 Form 10-K for additional details of the Company’s financial condition, results of operations and cash flows. No material items included in those notes have changed except as a result of normal transactions in the interim or as disclosed within this report.

*Basis of Presentation*

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information, pursuant to the rules and regulations of the SEC, including instructions to Quarterly Reports on Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements. In the opinion of management, all adjustments considered necessary for a fair statement of the unaudited consolidated financial statements have been included. All such adjustments are of a normal recurring nature. The consolidated financial statements should be read in conjunction with the 2016 Form 10-K. The consolidated results of operations for the three and nine months ended September 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

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. 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.

*Oil and Gas Properties - Successful Efforts*

Our application of the successful efforts method of accounting for our natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

*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 and nine months ended September 30, 2017. No impairment of proved properties was recognized for the three months ended September 30, 2016, and the Company recognized approximately $0.7 million impairment of proved properties for the nine months ended September 30, 2016, substantially all of which was directly related 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 no impairment of unproved properties for the three months ended September 30, 2017 and $1.4 million in impairment expense related to the partial impairment of two unused offshore platforms for the nine months ended September 30, 2017. 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 certain unproved properties due primarily to the sustained low commodity price environment and expiring leases, substantially all of which was related to unproved lease cost amortization of marginal, non-core properties in Fayette and Gonzales counties, Texas.

*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. Potentially dilutive securities, including unexercised stock options, Performance Stock Units and unvested restricted stock, have not been considered when their effect would be antidilutive. For the three months ended September 30, 2017, the Company excluded 971,813 potentially dilutive securities, as they were antidilutive, and excluded 813,151 potentially dilutive securities for the nine months ended September 30, 2017, as they were antidilutive.

For the three months ended September 30, 2016, the Company excluded 439,017 potentially dilutive securities, as they were antidilutive, and 382,867 potentially dilutive securities were excluded for the nine months ended September 30, 2016, as they were antidilutive.

*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 January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-01: Business Combinations (Topic 805) Clarifying the Definition of a Business (ASU 2017-01). The amendments in this update are intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. Public business entities should apply the amendments in this update to annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments in this update should be applied prospectively on or after the effective date. No disclosures are required at transition. The provisions of this accounting update are not expected to have a material impact on the Company's financial position or results of operations.

In August 2016, the FASB issued ASU 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 provisions of this accounting update are not expected to have a material impact on the Company's presentation of cash flows.

In February 2016, the FASB issued ASU 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 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. 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 May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Several additional standards related to revenue recognition have been issued that amend the original standard, with most providing additional clarification.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. The Company has completed its initial review of all revenue contracts. The Company's revenue contracts are normal purchase/sale contracts and as such, the Company does not expect that the new revenue recognition standard will have a material impact on the Company's financial statements upon adoption. The Company expects to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized at the date of the adoption of the standard.

**3. Acquisitions and Dispositions**

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 "Acquisition"). The purchase price was comprised of $10 million in cash paid on July 26, 2016, plus $10 million to be paid in the form of carried well costs expected to be paid over the period of drilling and completion of the first six wells. Additionally, contingent upon success, $5 million in spud bonuses is to be paid by the Company ratably over the following 14 wells drilled, which would increase the total consideration paid by the Company to $25 million. As of September 30, 2017, the Company had paid all $10 million of the carried well costs and $0.7 million in spud bonuses. As of September 30, 2017, the Company had increased its acreage to approximately 13,600 gross operated acres (6,800 net).

On December 30, 2016, all of the Company's non-core Colorado assets were sold to an independent oil and gas company for an aggregate purchase price of $5.0 million, subject to normal post-closing adjustments. The properties consisted of the Company's approximately 16,000 gross (11,200 net) acres primarily in Adams and Weld counties, Colorado and associated producing vertical wells.

Effective February 1, 2017, the Company sold to a third party all of its assets in the North Bob West area and its operated assets in the Escobas area, both located in Southeast Texas, for a cash purchase price of $650,000. The Company recorded a net gain of $2.9 million after removal of the asset retirement obligations associated with the sold properties.

**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, 2017. 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, 2017 (in thousands):

| | Total Carrying Value | Fair Value Measurements Using | | |
|---|---|---|---|---|
| | | Level 1 | Level 2 | Level 3 |
| Derivatives | | | | |
| Commodity price contracts - assets | $ 440 | $ — | $ 440 | $ — |
| Commodity price contracts - liabilities | $ (90) | $ — | $ (90) | $ — |

Derivatives listed above are recorded in “Current derivative asset or 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 (loss) on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 5 - "Derivative Instruments" for additional discussion of derivatives.

As of September 30, 2017, the Company's derivative contracts were with certain members of its credit facility lenders 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 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.

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.

*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. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3.

**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, 2017, the Company’s natural gas and oil 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 it 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 (loss) on derivatives, net" on the consolidated statements of operations.

The following derivative instruments were in place at September 30, 2017 (fair value in thousands):

| Commodity | Period | Derivative | Volume/Month | Price/Unit [1] | Fair Value |
|---|---|---|---|---|---|
| Natural Gas | Oct 2017 | Collar | 200,000 MMBtu | $ 2.65 - 3.00 | 0 |
| Natural Gas | Nov 2017 - Dec 2017 | Collar | 400,000 MMBtu | $ 2.65 - 3.00 | (90) |
| | | | | | |
| Natural Gas | Oct 2017 | Swap | 70,000 MMBtu | $ 3.51 | 37 |
| Natural Gas | Nov 2017 - Dec 2017 | Swap | 300,000 MMBtu | $ 3.51 | 246 |
| | | | | | |
| Oil | Oct 2017 | Swap | 6,000 Bbls | $ 53.95 | 13 |
| Oil | Nov 2017 - Dec 2017 | Swap | 8,000 Bbls | $ 53.95 | 30 |
| | | | | | |
| Oil | Oct 2017 - Dec 2017 | Swap | 9,000 Bbls | $ 56.20 | 114 |
| | | Total net fair value of derivative instruments | | | $ 350 |

(1) Commodity price derivatives are based on Henry Hub NYMEX natural gas prices and West Texas Intermediate oil prices, as applicable.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of September 30, 2017 (in thousands):

| | Gross | Netting (1) | Total |
|---|---|---|---|
| Assets | $ 440 | $ — | $ 440 |
| Liabilities | $ (90) | $ — | $ (90) |

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

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2016 (in thousands):

| | Gross | Netting (1) | Total |
|---|---|---|---|
| Assets | $ — | $ — | $ — |
| Liabilities | $ (3,446) | $ — | $ (3,446) |

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

The following table summarizes the effect of derivative contracts on the consolidated statements of operations for the three and nine months ended September 30, 2017 and 2016 (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Crude oil contracts | $ 342 | $ — | $ 879 | $ — |
| Natural gas contracts | 179 | (619) | (102) | 3,136 |
| Realized gain (loss) | $ 521 | $ (619) | $ 777 | $ 3,136 |
| | | | | |
| Crude oil contracts | $ (661) | $ — | $ 156 | $ — |
| Natural gas contracts | 131 | 1,532 | 3,641 | (2,400) |
| Unrealized gain (loss) | $ (530) | $ 1,532 | $ 3,797 | $ (2,400) |
| Gain (loss) on derivatives, net | $ (9) | $ 913 | $ 4,574 | $ 736 |

In October 2017, the Company entered into the following additional financial derivative contracts with a member of its credit facility lenders:

| Commodity | Period | Derivative | Volume/Month | Price/Unit (1) |
|---|---|---|---|---|
| Natural Gas | Jan 2018 - July 2018 | Swap | 370,000 MMBtu | $ 3.07 |
| Natural Gas | Aug 2018 - Oct 2018 | Swap | 70,000 MMBtu | $ 3.07 |
| Natural Gas | Nov 2018 - Dec 2018 | Swap | 320,000 MMBtu | $ 3.07 |
| | | | | |
| Oil | Jan 2018 - June 2018 | Swap | 20,000 Bbls | $ 56.40 |
| Oil | July 2018 - Oct 2018 | Collar | 20,000 Bbls | $ 52.00 - 56.85 |
| Oil | Nov 2018 - Dec 2018 | Collar | 15,000 Bbls | $ 52.00 - 56.85 |
| | | | | |
| Oil | Jan 2019 - Dec 2019 | Collar | 7,000 Bbls | $ 50.00 - 58.00 |

(1) Commodity price derivatives are based on Henry Hub NYMEX natural gas prices and Argus Louisiana Light Sweet oil prices, as applicable.

**6. Stock-Based Compensation**

The Company recognized approximately $4.6 million and $4.3 million in stock compensation expense during the nine months ended September 30, 2017 and 2016, respectively, for equity awards granted to its officers, employees and directors. As of September 30, 2017, an additional $6.2 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 2.1 years. This includes expense related to restricted stock, Performance Stock Units (“PSUs”) and stock options.

***Restricted Stock***

During the nine months ended September 30, 2017, the Company granted 383,376 shares of restricted common stock, which vest over three years, to new and existing employees as part of their overall compensation package, and 74,325 shares of restricted common stock, which vest over one year, to directors pursuant to the Company's Director Compensation Plan. The weighted average intrinsic value of the restricted shares granted during the nine months ended September 30, 2017, was $7.55 with a total fair value of approximately $3.5 million after adjustment for an estimated weighted average forfeiture rate of 5.7%. During the nine months ended September 30, 2017, 128,615 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the nine months ended September 30, 2017 was approximately $1.3 million. Approximately 1.6 million shares remained available for grant under the Amended and Restated 2009 Incentive Compensation Plan as of September 30, 2017, assuming PSUs are settled at 100% of target.

During the nine months ended September 30, 2016, the Company granted 40,876 immediately vested shares of restricted common stock. Of these, 38,943 shares were granted to employees and 1,933 shares were granted to directors, all of which were issued pursuant to the Company's salary replacement program (the "Salary Replacement Program") which temporarily deferred 10% of 2015 employee salaries and director fees. 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 over 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.

***Performance Stock Units***

During the nine months ended September 30, 2017, the Company granted 30,000 PSUs to a new employee, at a weighted average fair value of $8.32 per unit and 160,908 PSUs to executive officers, as part of their overall compensation package, at a value of $13.91 per unit. All prices were determined using the Monte Carlo simulation model. During the nine months ended September 30, 2017, 94,063 PSUs were forfeited by former employees. No PSUs were issued or forfeited during the nine months ended September 30, 2016. PSUs represent the opportunity to receive shares of the Company's common stock at the time of settlement. The number of shares to be awarded upon settlement of these PSUs may range from 0% to 300% of the number of PSUs awarded contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PSUs vest and settlement is determined after a three year period.

Compensation expense associated with PSUs is based on the grant date fair value of a single PSU as determined using the Monte Carlo simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As it is contemplated that the PSUs will be settled with shares of the Company's common stock after three years, the PSU awards are accounted for as equity awards and the fair value is calculated on the grant date. The simulation model calculates the payout percentage based on the stock price performance over the performance period. The concluded fair value is based on the average achievement percentage over all the iterations. The resulting fair value expense is amortized over the life of the PSU award.

***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, 2017 and 2016, 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, 2017 or 2016.

During the nine months ended September 30, 2017, no stock options were exercised, while 17,072 stock options were forfeited by former employees. During the nine months ended September 30, 2016, no stock options were exercised and stock options for 1,657 shares of common stock were forfeited.

**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, 2017 | December 31, 2016 |
|---|---|---|
| Accounts receivable: | | |
| Trade receivables | $ 7,262 | $ 8,424 |
| Receivable for Alta Resources Distribution | 1,993 | 1,993 |
| Joint interest billings | 2,972 | 3,519 |
| Income taxes receivable | 92 | 91 |
| Other receivables | 335 | 3,395 |
| Allowance for doubtful accounts | (897) | (695) |
| Total accounts receivable | $ 11,757 | $ 16,727 |
| | | |
| Prepaid expenses and other: | | |
| Prepaid insurance | $ 1,088 | $ 1,086 |
| Other | 698 | 701 |
| Total prepaid expenses and other | $ 1,786 | $ 1,787 |
| | | |
| Accounts payable and accrued liabilities: | | |
| Royalties and revenue payable | $ 19,343 | $ 16,920 |
| Advances from partners | 3,230 | 5,792 |
| Accrued exploration and development | 8,189 | 11,176 |
| Accrued carried well costs | — | 7,155 |
| Trade payables | 5,433 | 5,406 |
| Accrued LOE & workover expense | 2,228 | 1,867 |
| Accrued G&A and legal expense | 3,997 | 5,016 |
| Other accounts payable and accrued liabilities | 2,981 | 1,803 |
| Total accounts payable and accrued liabilities | $ 45,401 | $ 55,135 |

Included in the table below is supplemental information about certain cash and non-cash transactions during the nine months ended September 30, 2017 and 2016 (in thousands):

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2017 | 2016 |
| Cash payments: | | |
| Interest payments | $ 2,501 | $ 2,935 |
| Income tax payments (refunds) | $ 708 | $ (2,337) |
| Non-cash investing activities in the consolidated statements of cash flows: | | |
| Increase (decrease) in accrued capital expenditures | $ (10,142) | $ 7,248 |

**8. Investment in Exaro Energy III LLC**

The Company maintains an ownership interest in Exaro of approximately 37%.

The following table (in thousands) presents condensed balance sheet data for Exaro as of September 30, 2017 and December 31, 2016. The balance sheet data was derived from Exaro's balance sheet as of September 30, 2017 and December 31, 2016 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, 2017 was approximately $18.1 million.

| | September 30, 2017 | December 31, 2016 |
|---|---|---|
| Current assets [1] | $ 15,897 | $ 25,296 |
| Non-current assets: | | |
| Net property and equipment | 84,766 | 90,621 |
| Gas processing deposit | 1,150 | 1,150 |
| Other non-current assets | 57 | 8 |
| Total non-current assets | 85,973 | 91,779 |
| Total assets | $ 101,870 | $ 117,075 |
| | | |
| Current liabilities [2] | $ 3,950 | $ 65,694 |
| Non-current liabilities: | | |
| Long-term debt | 44,356 | — |
| Other non-current liabilities | 3,466 | 8,106 |
| Total non-current liabilities | 47,822 | 8,106 |
| Members' equity | 50,098 | 43,275 |
| Total liabilities & members' equity | $ 101,870 | $ 117,075 |

(1) Approximately $13.6 million and $19.6 million of current assets as of September 30, 2017 and December 31, 2016, respectively, is cash.
(2) Approximately $59.3 million of current liabilities as of December 31, 2016, was attributable to Exaro's senior loan facility maturing in 2017, which has since been refinanced.

The following table (in thousands) presents the condensed results of operations for Exaro for the three and nine months ended September 30, 2017 and 2016. The results of operations for the three and nine months ended September 30, 2017 and 2016 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, 2017 and 2016 was a gain of $0.5 million, net of no tax expense. The Company's share in Exaro's results of operations recognized for the nine months ended September 30, 2017 and 2016 was a gain of $2.5 million, net of no tax expense, and a gain of $1.8 million, net of no tax expense, respectively.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Production: | | | | |
| Oil (thousand barrels) | 24 | 30 | 77 | 98 |
| Gas (million cubic feet) | 2,216 | 2,659 | 6,797 | 8,083 |
| Total (million cubic feet equivalent) | 2,360 | 2,839 | 7,260 | 8,671 |
| | | | | |
| Oil and natural gas sales | $ 7,483 | $ 8,242 | $ 24,499 | $ 20,730 |
| Gain (loss) on derivatives | 318 | 1,011 | 3,720 | (1,231) |
| Other gain | — | — | — | 10,441 |
| Less: | | | | |
| Lease operating expenses | 2,928 | 3,969 | 10,914 | 11,513 |
| Depreciation, depletion, amortization & accretion | 2,143 | 2,880 | 6,734 | 8,705 |
| General & administrative expense | 701 | 671 | 2,308 | 2,605 |
| Income from continuing operations | 2,029 | 1,733 | 8,263 | 7,117 |
| Net interest expense | (629) | (598) | (1,582) | (1,994) |
| Net income | $ 1,400 | $ 1,135 | $ 6,681 | $ 5,123 |

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

**9. Long-Term Debt**

*RBC Credit Facility*

In October 2013, the Company entered into a $500 million revolving credit facility with Royal Bank of Canada and other lenders (the “RBC Credit Facility”), which matures on October 1, 2019. The borrowing base under the facility is redetermined each November and May. The Company is currently going through the redetermination process, but does not expect a material reduction that would affect its liquidity. As of September 30, 2017, the borrowing base under the RBC Credit Facility was $125 million.

As of September 30, 2017, the Company had approximately $79.2 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of December 31, 2016, the Company had approximately $54.4 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of September 30, 2017, borrowing availability under the RBC Credit Facility was $43.9 million.

Total interest expense under the RBC Credit Facility, including commitment fees, for the three and nine months ended September 30, 2017 was approximately $1.1 million and $2.8 million, respectively. 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.

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, 2017, the Company was in compliance with all financial covenants under the RBC Credit Facility. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at September 30, 2017 and December 31, 2016 was 4.9% and 4.2%, 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, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Current tax provision: | | | | |
| Federal | $ — | $ — | $ — | $ — |
| State | 88 | 51 | 397 | 410 |
| Total | $ 88 | $ 51 | $ 397 | $ 410 |
| Total tax provision: | | | | |
| Federal | $ — | $ — | $ — | $ — |
| State | 88 | 51 | 397 | 410 |
| Total | $ 88 | $ 51 | $ 397 | $ 410 |
| Included in gain from investment in affiliates | $ — | $ — | $ — | $ — |
| Total income tax provision | $ 88 | $ 51 | $ 397 | $ 410 |

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that the deferred tax assets will be realized and, therefore, established a full valuation allowance at September 30, 2015. For the nine months ended September 30, 2017, 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**

*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 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, 2017, Mr. Romano earned $15 thousand and $42 thousand for his service as a director of the Company, respectively. 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.

In May 2017, Mr. Romano received 14,865 shares of restricted stock, which vest in one year, as part of his board of director compensation. The Company recognized compensation expense of approximately $28 thousand and $90 thousand related to the shares granted to Mr. Romano for the three and nine months ended September 30, 2017, respectively. In January 2016, Mr. Romano received 261 shares of restricted stock, which vested immediately, 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. During the three and nine months ended September 30, 2016, the Company recognized compensation expense of approximately $30 thousand and $70 thousand, respectively, related to the shares granted to Mr. Romano.

Below is a summary of payments received from (paid to) Olympic 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, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Revenue payments as well owners | $ (634) | $ (617) | $ (2,071) | $ (1,788) |
| Joint interest billing receipts | 111 | 149 | 306 | 272 |

As of September 30, 2017 and December 31, 2016, the Company's consolidated balance sheets reflected the following balances relating to Olympic (in thousands):

| | September 30, 2017 | December 31, 2016 |
|---|---|---|
| Accounts receivable: | | |
| Joint interest billing | $ 26 | $ 59 |
| Accounts payable: | | |
| Royalties and revenue payable | (448) | (557) |

*Oaktree Capital Management L.P.*

As of September 30, 2017, Oaktree Capital Management L.P. ("Oaktree"), through various funds, owned approximately 5.1% 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. Beginning in October 2016, all cash and equity awards payable to Oaktree for Mr. Ford's service as a director became payable to him directly. During the three and nine months ended September 30, 2017, Mr. Ford earned $18 thousand and $50 thousand in cash as a result of his board participation, respectively. During the three and nine months ended September 30, 2016, an affiliate of Oaktree earned $18 thousand and $50 thousand in cash as a result of Mr. Ford's board participation, respectively.

In May 2017, Mr. Ford received 14,865 shares of restricted stock, which vest in one year, as part of his board of director compensation. The Company recognized compensation expense of approximately $28 thousand and $90 thousand related to the shares granted to Mr. Ford for the three and nine months ended September 30, 2017, respectively. In January 2016, an affiliate of Oaktree received 313 shares of restricted stock, which vested immediately, 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. During the three and nine months ended September 30, 2016, the Company recognized compensation expense of approximately $30 thousand and $70 thousand, respectively, related to the shares granted to an affiliate of Oaktree.

**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 the Company's 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 the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company is vigorously defending this lawsuit, believes that it has meritorious defenses and is appealing the trial court's decision to the applicable state Court of Appeals.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company 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.

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 natural gas gathering pipeline in the Company's Southeast Texas area that allows the Company to defray the cost of building the pipeline itself. The Company currently forecasts that monthly gas volume deliveries through this line in its Southeast Texas area will not meet minimum throughput requirements under the agreement. Without further development in that area, the volume deficiency will continue through the expiration of the throughput commitment in March 2020. The throughput deficiency fee is paid in April of each calendar year. The Company estimates that the net deficiency fee will be approximately $1.0 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. As of September 30, 2017, based upon the current commodity price market and our short term strategic drilling plans, the Company has recorded a $0.8 million loss contingency through December 31, 2017. The Company will continue to assess this commitment in light of its development plans for this area.

**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 identify 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 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 capital 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 proceeds from the sale of our production;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures, and other risks;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;
- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals;
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;

- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements; and
- 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.

**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 2016 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 offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore Texas and Wyoming properties and to use that cash flow to explore, develop, exploit and acquire crude oil and natural gas properties in the Texas and Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of September 30, 2017:

| Location | Formation |
|---|---|
| Gulf of Mexico | Offshore Louisiana - water depths less than 300 feet |
| Madison and Grimes counties, Texas | Woodbine (Upper Lewisville) |
| Pecos County, Texas | Southern Delaware Basin (Wolfcamp) |
| Texas Gulf Coast | Conventional and unconventional formations |
| Zavala and Dimmit counties, Texas | Buda / Austin Chalk |
| Weston County, Wyoming | Muddy Sandstone |
| 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 months ended September 30, 2017.

In July 2016, we purchased approximately 12,100 gross operated undeveloped acres (5,000 net acres) in the Southern Delaware Basin in Pecos County, Texas (the "Acquisition"), which we began drilling during the fourth quarter of 2016, and increased our acreage to approximately 13,600 gross operated acres (6,800 net) as of September 30, 2017.

Our 2017 capital program has focused, and will continue to focus, on the development of our Southern Delaware Basin acreage. Additionally, we will continue to identify opportunities for cost efficiencies in all areas of our operations, maintain core leases and continue to identify new resource potential opportunities internally and, where appropriate, through acquisition. We will continuously monitor the commodity price environment, including its stability and forecast, and, if warranted, make adjustments to our strategy as the year progresses.

**Capital Expenditures**

Our Southern Delaware Basin acreage has generated, and is expected to continue to generate, positive returns on drilling investment, even in the current commodity price environment. Assuming we achieve our expected results and market conditions do not deteriorate, we will continue to drill throughout the year. Until a sustained improvement in commodity prices occurs, however, we do not currently expect to devote meaningful capital to the development of our other areas, and will devote capital to those areas to fulfill commitments, preserve core acreage and, where determined appropriate to do so, expand our presence in existing areas. We will continue to make balance sheet strength a priority in 2017, will continue to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed acquisition opportunities that may arise in this low commodity price environment. We retain the flexibility to be more aggressive in our drilling plans should actual results exceed expectations and/or commodity prices improve, thereby making increased drilling an appropriate business decision.

*Southern Delaware Basin*

Since the closing of the Acquisition, we and our partner have increased our leasehold footprint to approximately 13,600 gross operated acres, or approximately 6,800 net acres to Contango. As of September 30, 2017, we currently estimate that we have close to 200 gross drilling locations in the Southern Delaware Basin, initially targeting the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. Substantially all of these locations can accommodate 10,000 foot laterals. In January 2017, we initiated flowback on our first well in the Southern Delaware Basin, the

Lonestar-Gunfighter #1H, an Upper Wolfcamp A test well in the northwest portion of our acreage position, on a controlled flow basis, reaching a maximum 24-hour initial production ("IP") rate of 966 Boed (72% oil).

Our next two wells, the Rude Ram #1H and the Ripper State #1H, were drilled from a common surface location one mile south of the Lonestar-Gunfighter #1H, each well also targeting the Upper Wolfcamp A. Both wells initiated flow back in May 2017. The Rude Ram #1H reached a maximum 24-hour IP rate of 1,304 Boed (69% oil), while the Ripper State #1H reached a maximum 24-hour IP rate of 1,131 Boed (73% oil). In February 2017, we spud a pilot test well, the Grim Reaper #1H, approximately 1.5 miles to the southeast of the Rude Ram and Ripper State. The Grim Reaper was initially drilled as a pilot well through the Lower Wolfcamp, and after experiencing casing problems in the intermediate hole section, logs were run, and the well was completed vertically with multistage fracs in the Lower Wolfcamp to evaluate future potential.

Our fourth horizontal well in the area, the Gunner #2H, was spud in April 2017, targeting the Lower Wolfcamp A. The Gunner #2H is approximately two miles to the northeast of the Grim Reaper #1H and initiated flow back in early August 2017, reaching a maximum 24-hour IP rate of 1,348 Boed (77% oil). In June 2017, we spud the Fighting Ace #1H which encountered mechanical difficulties and was temporarily abandoned. We expect this well bore could have future utility for a possible shallower Bone Springs test.

Our fifth horizontal well, the Crusader #1H, was spud in June 2017, targeting the Lower Wolfcamp A. Completion operations with 50 stages of fracture stimulation are expected to commence in early January 2018. Our sixth horizontal well, the Ragin Bull #1H was spud in September 2017 targeting the Wolfcamp formation to satisfy lease considerations and we are currently in the lateral section.

**Impairment of Long-Lived Assets**

We recognized no impairment of proved properties during the three and nine months ended September 30, 2017. Under GAAP, 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. We recognized no impairment of unproved properties for the three months ended September 30, 2017 and $1.4 million in impairment expense related to the partial impairment of two unused offshore platforms for the nine months ended September 30, 2017.

**Summary Production Information**

Our production for the three months ended September 30, 2017 was approximately 69% offshore and 31% onshore and was comprised of 68% natural gas, 16% oil and 16% natural gas liquids. Our production for the three months ended September 30, 2016 was 67% offshore and 33% onshore and was comprised of approximately 71% natural gas, 12% oil and 17% 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, 2016 | December 31, 2016 | March 31, 2017 | June 30, 2017 | September 30, 2017 |
| Offshore GOM | | | | | |
| Dutch and Mary Rose (1) | 39.3 | 39.5 | 35.4 | 36.3 | 32.2 |
| Vermilion 170 (2) | 4.0 | 4.9 | 4.6 | 3.1 | 4.2 |
| South Timbalier 17 (3) | 0.6 | 0.6 | 0.5 | 0.2 | 0.1 |
| Southeast Texas (4) | 12.1 | 10.1 | 8.6 | 8.2 | 7.8 |
| South Texas (5) | 7.5 | 7.5 | 6.4 | 5.6 | 4.6 |
| Other (6) | 2.2 | 1.7 | 2.1 | 4.6 | 4.3 |
| | 65.7 | 64.3 | 57.6 | 58.0 | 53.2 |

(1) Includes 26 day shut in for compressor repair during the three months ended March 31, 2017.
(2) Includes a decreased production rate of 0.8 Mmcfe/d due to temporary pipeline limitations during the three months ended June 30, 2017.
(3) South Timbalier 17 ceased production in August 2017.
(4) Includes Madison and Grimes counties, among others.
(5) Includes Zavala and Dimmit counties, among others.
(6) Includes onshore wells primarily in Colorado, East Texas, and Wyoming during 2016 and onshore wells primarily in East Texas, Wyoming and West Texas during 2017.

**Other Investments**

*Jonah Field - Sublette County, Wyoming*

Our wholly owned subsidiary, Contaro Company ("Contaro") currently has a 37% ownership interest in Exaro. As of September 30, 2017, Exaro had 646 wells on production over its 5,760 gross acres (1,040 net), with a working interest between 2.4% and 32.5%. These wells were producing at a rate of approximately 27 Mmcfed, net to Exaro. The operator of these interests has applied for multiple drilling permits for horizontal wells that will be located on parts of our acreage. Exaro's working interest in the drilling spacing units for the applied for horizontal wells ranges from 1% to 6%. As of September 30, 2017, the operator has been approved to drill two horizontal wells, in which Exaro has a net working interest of 2.4%. For the three months ended September 30, 2017 and 2016, we recognized an investment gain of approximately $0.5 million, net of no tax expense, as a result of our investment in Exaro. For the nine months ended September 30, 2017 and 2016, we recognized an investment gain of approximately $2.5 million, net of no tax expense, and a gain of approximately $1.8 million, net of no tax expense, respectively. 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.

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**Results of Operations for the Three and Nine months Ended September 30, 2017 and 2016**

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, 2017 and 2016. 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, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | % | 2017 | 2016 | % |
| Revenues (thousands): | | | | | | |
| Oil and condensate sales | $ 6,109 | $ 4,946 | 24 % | $ 18,134 | $ 17,164 | 6 % |
| Natural gas sales | 9,681 | 12,011 | (19)% | 31,956 | 31,283 | 2 % |
| NGL sales | 3,040 | 2,619 | 16 % | 8,440 | 8,073 | 5 % |
| Total revenues | $ 18,830 | $ 19,576 | (4)% | $ 58,530 | $ 56,520 | 4 % |
| | | | | | | |
| Production: | | | | | | |
| Oil and condensate (thousand barrels) | | | | | | |
| Offshore GOM | 23 | 19 | 21 % | 78 | 106 | (26)% |
| Southeast Texas | 35 | 54 | (35)% | 117 | 190 | (38)% |
| South Texas | 19 | 28 | (32)% | 68 | 95 | (28)% |
| Other | 55 | 18 | 206 % | 125 | 79 | 58 % |
| Total oil and condensate | 132 | 119 | 11 % | 388 | 470 | (17)% |
| Natural gas (million cubic feet) | | | | | | |
| Offshore GOM | 2,702 | 3,327 | (19)% | 8,618 | 10,841 | (21)% |
| Southeast Texas | 324 | 469 | (31)% | 999 | 1,666 | (40)% |
| South Texas | 232 | 407 | (43)% | 837 | 1,137 | (26)% |
| Other | 57 | 92 | (38)% | 196 | 245 | (20)% |
| Total natural gas | 3,315 | 4,295 | (23)% | 10,650 | 13,889 | (23)% |
| Natural gas liquids (thousand barrels) | | | | | | |
| Offshore GOM | 87 | 99 | (12)% | 254 | 323 | (21)% |
| Southeast Texas | 31 | 53 | (42)% | 89 | 176 | (49)% |
| South Texas | 13 | 19 | (32)% | 43 | 55 | (22)% |
| Other | 1 | 2 | (50)% | 11 | 6 | 83 % |
| Total natural gas liquids | 132 | 173 | (24)% | 397 | 560 | (29)% |
| Total (million cubic feet equivalent) | | | | | | |
| Offshore GOM | 3,360 | 4,035 | (17)% | 10,608 | 13,415 | (21)% |
| Southeast Texas | 721 | 1,113 | (35)% | 2,239 | 3,866 | (42)% |
| South Texas | 424 | 689 | (38)% | 1,507 | 2,035 | (26)% |
| Other | 396 | 210 | 89 % | 1,005 | 750 | 34 % |
| Total production | 4,901 | 6,047 | (19)% | 15,359 | 20,066 | (23)% |
| | | | | | | |
| Daily Production: | | | | | | |
| Oil and condensate (thousand barrels per day) | | | | | | |
| Offshore GOM | 0.2 | 0.2 | 21 % | 0.3 | 0.4 | (26)% |
| Southeast Texas | 0.4 | 0.6 | (35)% | 0.4 | 0.7 | (38)% |
| South Texas | 0.2 | 0.3 | (32)% | 0.3 | 0.3 | (28)% |
| Other | 0.6 | 0.2 | 206 % | 0.4 | 0.3 | 58 % |
| Total oil and condensate | 1.4 | 1.3 | 11 % | 1.4 | 1.7 | (17)% |
| Natural gas (million cubic feet per day) | | | | | | |
| Offshore GOM | 29.4 | 36.2 | (19)% | 31.6 | 39.5 | (21)% |
| Southeast Texas | 3.5 | 5.1 | (31)% | 3.7 | 6.1 | (40)% |
| South Texas | 2.5 | 4.4 | (43)% | 3.1 | 4.1 | (26)% |
| Other | 0.6 | 1.0 | (38)% | 0.6 | 0.9 | (20)% |
| Total natural gas | 36.0 | 46.7 | (23)% | 39.0 | 50.6 | (23)% |

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | % | 2017 | 2016 | % |
| Natural gas liquids (thousand barrels per day) | | | | | | |
| Offshore GOM | 0.9 | 1.1 | (12)% | 1.0 | 1.2 | (21)% |
| Southeast Texas | 0.3 | 0.6 | (42)% | 0.3 | 0.6 | (49)% |
| South Texas | 0.1 | 0.2 | (32)% | 0.2 | 0.2 | (22)% |
| Other | 0.1 | — | (50)% | — | — | 83 % |
| Total natural gas liquids | 1.4 | 1.9 | (24)% | 1.5 | 2.0 | (29)% |
| Total (million cubic feet equivalent per day) | | | | | | |
| Offshore GOM | 36.5 | 43.9 | (17)% | 38.9 | 48.9 | (21)% |
| Southeast Texas | 7.8 | 12.1 | (35)% | 8.2 | 14.1 | (42)% |
| South Texas | 4.6 | 7.5 | (38)% | 5.5 | 7.4 | (26)% |
| Other | 4.3 | 2.2 | 89 % | 3.7 | 2.8 | 34 % |
| Total production | 53.2 | 65.7 | (19)% | 56.3 | 73.2 | (23)% |
| | | | | | | |
| Average Sales Price: | | | | | | |
| Oil and condensate (per barrel) | $ 46.30 | $ 41.63 | 11 % | $ 46.76 | $ 36.49 | 28 % |
| Natural gas (per thousand cubic feet) | $ 2.92 | $ 2.80 | 4 % | $ 3.00 | $ 2.25 | 33 % |
| Natural gas liquids (per barrel) | $ 22.98 | $ 15.10 | 52 % | $ 21.26 | $ 14.40 | 48 % |
| Total (per thousand cubic feet equivalent) | $ 3.84 | $ 3.24 | 19 % | $ 3.81 | $ 2.82 | 35 % |
| | | | | | | |
| Expenses (thousands): | | | | | | |
| Operating expenses | $ 7,041 | $ 8,158 | (14)% | $ 20,203 | $ 22,782 | (11)% |
| Exploration expenses | $ 315 | $ 444 | (29)% | $ 690 | $ 1,088 | (37)% |
| Depreciation, depletion and amortization | $ 11,193 | $ 15,166 | (26)% | $ 35,678 | $ 49,586 | (28)% |
| Impairment and abandonment of oil and gas properties | $ 84 | $ 1,165 | (93)% | $ 1,515 | $ 4,268 | (65)% |
| General and administrative expenses | $ 6,219 | $ 7,486 | (17)% | $ 18,648 | $ 18,772 | (1)% |
| Gain from investment in affiliates (net of taxes) | $ 525 | $ 467 | 12 % | $ 2,475 | $ 1,802 | 37 % |
| | | | | | | |
| Selected data per Mcfe: | | | | | | |
| Operating expenses | $ 1.44 | $ 1.35 | 7 % | $ 1.32 | $ 1.14 | 16 % |
| General and administrative expenses | $ 1.27 | $ 1.24 | 2 % | $ 1.21 | $ 0.94 | 29 % |
| Depreciation, depletion and amortization | $ 2.28 | $ 2.51 | (9)% | $ 2.32 | $ 2.47 | (6)% |

**Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016**

*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 significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production naturally declines over time as we produce our reserves.

We reported revenues of $18.8 million for the three months ended September 30, 2017, compared to revenues of $19.6 million for the three months ended September 30, 2016. The decrease in revenues was attributable to lower production and non-core property sales, which was partially offset by higher commodity prices.

Total equivalent production was 53.2 Mmcfed for the three months ended September 30, 2017, compared to 65.7 Mmcfed in the prior year quarter. The decrease was attributable to a 12.9 Mmcfed decrease in production resulting from normal field decline and limited 2016 drilling, a 1.6 Mmcfed decline from downtime associated with the impact of Hurricane Harvey, and a 1.2 Mmcfed decline from non-core property sales, offset in part by 3.2 Mmcfed of new production from drilling on our Southern Delaware Basin acreage.

*Average Sales Prices*

The average equivalent sales price realized for the three months ended September 30, 2017 was $3.84 per Mcfe compared to $3.24 per Mcfe for the three months ended September 30, 2016. This increase was attributable primarily to the increase in the realized price of oil to $46.30 per barrel, compared to $41.63 per barrel for the three months ended September 30, 2016, and to the increase in the realized price of natural gas liquids to $22.98 per barrel, compared to $15.10 per barrel for the three months ended September 30, 2016.

*Operating Expenses*

Operating expenses for the three months ended September 30, 2017 were approximately $7.0 million, or $1.44 per Mcfe, compared to $8.2 million, or $1.35 per Mcfe, for the three months ended September 30, 2016. The table below provides additional detail of operating expenses for the three month periods:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| | (in thousands) | (per Mcfe) | (in thousands) | (per Mcfe) |
| Lease operating expenses | $ 4,585 | 0.94 | $ 4,580 | $ 0.76 |
| Production & ad valorem taxes | 625 | 0.13 | 755 | 0.12 |
| Transportation & processing costs | 868 | 0.18 | 2,188 | 0.36 |
| Workover costs | 963 | 0.19 | 635 | 0.11 |
| Total operating expenses | $ 7,041 | 1.44 | $ 8,158 | $ 1.35 |

Production and ad valorem taxes decreased by 17% for the three months ended September 30, 2017, compared to the three months ended September 30, 2016, primarily as a result of property sales and lower legacy production, partially offset by production taxes on new West Texas production.

Transportation & processing costs decreased by 60% for the three months ended September 30, 2017, compared to the three months ended September 30, 2016, due to a higher minimum volume charge in 2016 for an ongoing throughput deficiency in our Madisonville Field. See Note 12 to our Financial Statements - “Commitments and Contingencies” for additional details related to this fee.

*Impairment Expenses*

No impairment expense was recorded for the three months ended September 30, 2017. Impairment expense for the three months ended September 30, 2016 included a $1.1 million impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases, substantially all of which was related to unproved lease cost amortization of marginal, non-core properties in Fayette and Gonzales counties, Texas.

*Depreciation, Depletion and Amortization*

Depreciation, depletion and amortization for the three months ended September 30, 2017 was approximately $11.2 million, or $2.28 per Mcfe. This compares to approximately $15.2 million, or $2.51 per Mcfe, for the three months ended September 30, 2016. The lower depletion for the three months ended September 30, 2017 was primarily attributable to lower production.

*General and Administrative Expenses*

General and administrative expenses for the three months ended September 30, 2017 were approximately $6.2 million, compared to $7.5 million for the three months ended September 30, 2016. These expenses are primarily related to cash compensation and benefits, stock based compensation, professional fees and office costs. General and administrative expenses for the three months ended September 30, 2016 were higher primarily due to payout of the Company’s salary replacement program, which temporarily deferred 10% of 2015 employee salaries and director fees, and an adjustment to the 2016 bonus accrual due to the improvement in performance compared to goals. General and administrative expenses also included approximately $1.5 million and $1.3 million in non-cash stock based compensation, for the current and prior year quarters, respectively.

*Gain from Affiliates*

For the three months ended September 30, 2017 and 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.

**Nine months Ended September 30, 2017 Compared to Nine months Ended September 30, 2016**

*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 significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production naturally declines over time as we produce our reserves.

We reported revenues of $58.5 million for the nine months ended September 30, 2017, compared to revenues of $56.5 million for the nine months ended September 30, 2016. The increase in revenues was attributable to higher commodity prices, which offset the decline in production caused by limited drilling in 2016 due to the low and uncertain commodity price environment and non-core property sales.

Total equivalent production was 56.3 Mmcfed for the nine months ended September 30, 2017, compared to 73.2 Mmcfed for the nine months ended September 30, 2016. The decrease was attributable to a 17.4 Mmcfed decline in production from normal field decline and limited 2016 drilling, a 1.1 Mmcfed decline due to non-core property sales, a 0.5 Mmcfed decline from downtime associated with the impact of Hurricane Harvey, and a 0.3 Mmcfed decline due to temporary pipeline limitations at the Vermillion 170 field. The decrease in production was partially offset by 2.4 Mmcfed of new production from drilling on our Southern Delaware Basin acreage.

*Average Sales Prices*

The average equivalent sales price realized for the nine months ended September 30, 2017 was $3.81 per Mcfe compared to $2.82 per Mcfe for the nine months ended September 30, 2016. This increase was attributable primarily to the increase in the realized price of natural gas to $3.00 per Mcf, compared to $2.25 per Mcf for the nine months ended September 30, 2016 and to the increase in the realized price of natural gas liquids to $21.26 per barrel, compared to $14.40 per barrel for the nine months ended September 30, 2016.

*Operating Expenses*

Operating expenses for the nine months ended September 30, 2017 were approximately $20.2 million, or $1.32 per Mcfe, compared to $22.8 million, or $1.14 per Mcfe, for the nine months ended September 30, 2016. The table below provides additional detail of operating expenses for the nine month periods:

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| | (in thousands) | (per Mcfe) | (in thousands) | (per Mcfe) |
| Lease operating expenses | $ 13,428 | $ 0.87 | $ 14,487 | $ 0.72 |
| Production & ad valorem taxes | 1,993 | 0.13 | 2,809 | 0.14 |
| Transportation & processing costs | 2,982 | 0.19 | 4,397 | 0.23 |
| Workover costs | 1,800 | 0.13 | 1,089 | 0.05 |
| Total operating expenses | $ 20,203 | 1.32 | $ 22,782 | $ 1.14 |

Production and ad valorem taxes decreased by 29% for the nine months ended September 30, 2017, compared to the nine months ended September 30, 2016, primarily as a result of property sales and lower legacy production, partially offset by production taxes on new West Texas production.

Transportation & processing costs decreased by 32% for the nine months ended September 30, 2017, compared to the nine months ended September 30, 2016, due to a final minimum volume charge on two wells in our South Texas region in 2016, a higher minimum volume charge in 2016 for an ongoing throughput deficiency in our Madisonville Field, and transportation costs on higher 2016 production from our Dutch and Mary Rose Field. See Note 12 to our Financial Statements - "Commitments and Contingencies" for additional details related to the Madisonville Field fee.

*Impairment Expenses*

Impairment expense for the nine months ended September 30, 2017 was $1.4 million related to the partial impairment of two unused offshore platforms. Impairment expense 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 prior year period was related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Impairment expense for the nine months ended September 30, 2016 also included a $3.4 million impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases, substantially all of which was related to unproved lease cost amortization of marginal, non-core properties in Fayette and Gonzales counties, Texas.

*Depreciation, Depletion and Amortization*

Depreciation, depletion and amortization for the nine months ended September 30, 2017 was approximately $35.7 million, or $2.32 per Mcfe. This compares to approximately $49.6 million, or $2.47 per Mcfe, for the nine months ended September 30, 2016. The lower depletion for the nine months ended September 30, 2017 was primarily attributable to lower production.

*General and Administrative Expenses*

General and administrative expenses for the nine months ended September 30, 2017 were approximately $18.6 million, compared to $18.8 million for the nine months ended September 30, 2016. General and administrative expenses are primarily related to cash compensation and benefits, stock based compensation, professional fees and office costs. General and administrative expenses for the current year included approximately $4.6 million in non-cash stock based compensation, while the prior year included approximately $4.3 million in non-cash stock based compensation.

*Gain from Affiliates*

For the nine months ended September 30, 2017, the Company recorded a gain from affiliates of approximately $2.5 million, net of no tax expense, related to our investment in Exaro, compared to a gain of $1.8 million, net of no tax expense, for nine months ended September 30, 2016.

**Capital Resources and Liquidity**

During the nine months ended September 30, 2017, we incurred expenditures of $37.6 million on capital projects, including $7.4 million in leasehold acquisition costs and $30.2 million for the drilling and completion of wells in the Southern Delaware Basin. As of September 30, 2017, our capital expenditure budget for 2017 was approximately $45 million, including $36.4 million to drill and/or complete eight horizontal gross wells (3.7 net), a vertical pilot well, a saltwater disposal well and central facilities, all in our Southern Delaware Basin position.

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 $26.1 million in cash for the nine months ended September 30, 2017 compared to $23.6 million provided by operating activities for the same period in 2016. The table below provides additional detail of cash flows from operating activities for the nine months ended September 30, 2017 and 2016:

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2017 | 2016 |
| | (in thousands) | |
| Cash flows from operating activities, exclusive of changes in working capital accounts | $ 20,733 | $ 17,438 |
| Changes in operating assets and liabilities | 5,372 | 6,158 |
| Net cash provided by operating activities | $ 26,105 | $ 23,596 |

*Cash From Investing Activities*

Cash flows used in investing activities for the nine months ended September 30, 2017 were approximately $50.8 million, substantially all of which was used for capital expenditures related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases. 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 acquiring acreage and unproved leases in the Southern Delaware Basin, completing one well in Wyoming, and acquiring or extending unproved leases in other core areas. Amounts presented include cash payments for accrued amounts at the beginning of each period.

*Cash From Financing Activities*

Cash flows provided by financing activities for the nine months ended September 30, 2017 were approximately $24.7 million, primarily related to net borrowings under our credit facility with the Royal Bank of Canada and other lenders (the "RBC Credit Facility"). Cash flows used in financing activities for the nine months ended September 30, 2016 were approximately $3.8 million, primarily related to the repayment of net borrowings under our RBC Credit Facility.

*RBC Credit Facility*

In October 2013, we entered into a $500 million revolving credit facility with Royal Bank of Canada and other lenders, which matures on October 1, 2019. The borrowing base is redetermined each November and May. We are currently going through the redetermination process, but do not expect a material reduction that would affect our liquidity. As of September 30, 2017, the borrowing base under the RBC Credit Facility was $125 million.

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, 2017, we were in compliance with all covenants under the RBC Credit Facility. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

**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 2016 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, 2017, 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 2016 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 Price 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 for our oil, natural gas and natural gas liquids production. 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 oil, natural gas and natural gas liquids are volatile and unpredictable. For the three and nine months ended September 30, 2017, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $1.9 million and $5.9 million impact on our revenues, respectively.

*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 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, 2017, 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.

*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, 2017, our total long-term debt was $79.2 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, 2017, our effective rates fluctuated between 4.0% and 7.3%, depending on the term of the specific debt drawdowns. At September 30, 2017, we did not have any outstanding interest rate swap agreements. As of September 30, 2017, the weighted average interest rate on our variable rate debt was 4.90% 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 $0.6 million for the nine month period.

*Other Financial Instruments*

As of September 30, 2017, 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, 2017, an immediate 10% change in interest rates would result in a $0.4 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, 2017. Based upon that evaluation, the Company's management concluded that, as of September 30, 2017, the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to ensure that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our President and Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2017 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, 2016.

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

None.

**Item 3.** ***Defaults upon Senior Securities***

None.

**Item 4.** ***Mine Safety Disclosures***

Not applicable.

**Item 5.** ***Other Information***

None.

**Item 6.** ***Exhibits***

| Exhibit Number | Description |
| --- | --- |
| 3.1 | Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.1 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, and incorporated by reference herein). |
| 3.2 | Amendment to the Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.4 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, and incorporated by reference herein). |
| 3.3 | Third Amended and Restated Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.2 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, and incorporated by reference herein). |
| 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.

## 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 8, 2017 | By: | /S/ ALLAN D. KEEL<br>**Allan D. Keel**<br>**President and Chief Executive Officer**<br>**(Principal Executive Officer)** |
| Date: November 8, 2017 | By: | /S/ E. JOSEPH GRADY<br>**E. Joseph Grady**<br>**Senior Vice President and Chief Financial Officer**<br>**(Principal Financial Officer)** |
| Date: November 8, 2017 | By: | /S/ DENISE DUBARD<br>**Denise DuBard**<br>**Chief Accounting Officer and Controller**<br>**(Principal Accounting Officer)** |

Exhibit 31.1

**CONTANGO OIL & GAS COMPANY**

**Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934**

I, Allan D. Keel, President and Chief Executive Officer of Contango Oil & Gas Company (the “Company”), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Company’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company’s auditors and the audit committee of the Company’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company’s internal control over financial reporting.

Date: November 8, 2017

By: /s/ ALLAN D. KEEL

**Allan D. Keel**
**President and Chief Executive Officer**
**(Principal Executive Officer)**

**Exhibit 31.2**

**CONTANGO OIL & GAS COMPANY**

**Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934**

I, E. Joseph Grady, Chief Financial Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: November 8, 2017

By: /s/ E. JOSEPH GRADY

**E. Joseph Grady**
**Senior Vice President and Chief Financial Officer**
**(Principal Financial Officer)**

Exhibit 32.1

**CONTANGO OIL & GAS COMPANY**

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Contango Oil & Gas Company (the "Company") on Form 10-Q for the quarter ended September 30, 2017 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Allan D. Keel, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 8, 2017

By: /s/ ALLAN D. KEEL

**Allan D. Keel**
**President and Chief Executive Officer**
**(Principal Executive Officer)**

**Exhibit 32.2**

**CONTANGO OIL & GAS COMPANY**

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Contango Oil & Gas Company (the "Company") on Form 10-Q for the quarter ended September 30, 2017 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, E. Joseph Grady, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 8, 2017

By: /s/ E. JOSEPH GRADY

**E. Joseph Grady**
**Senior Vice President and Chief Financial Officer**
**(Principal Financial Officer)**