CONTANGO OIL & GAS CO
Form 10-Q
August 11, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from to

Commission file number 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE	95-4079863
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

717 TEXAS, SUITE 2900

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

(713) 236-7400

(Registrant's telephone number, including area code)

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

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

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

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

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

The total number of shares of common stock, par value $0.04 per share, outstanding as of August 8, 2014 was 19,380,246.

1

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE SIX MONTHS ENDED JUNE 30, 2014

TABLE OF CONTENTS

		Page
	PART I—FINANCIAL INFORMATION	
Item 1.	Consolidated Financial Statements	
	Consolidated Balance Sheets (unaudited) as of June 30, 2014 and December 31, 2013	3
	Consolidated Statements of Operations (unaudited) for the three and six months ended June 30, 2014 and 2013	4
	Consolidated Statements of Cash Flows (unaudited) for the six months ended June 30, 2014 and 2013	5
	Consolidated Statement of Shareholders' Equity (unaudited) for the six months ended June 30, 2014	6
	Notes to the Unaudited Consolidated Financial Statements (unaudited)	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	21
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	34
Item 4.	Controls and Procedures	36
	PART II—OTHER INFORMATION	
Item 1.	Legal Proceedings	36
Item 1A.	Risk Factors	37
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	37
Item 3.	Defaults upon Senior Securities	37
Item 4.	Mine Safety Disclosures	37
Item 5.	Other Information	37
Item 6.	Exhibits	37

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

Item 1. Consolidated Financial Statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	June 30, 2014	December 31, 2013
	(unaudited)	
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	37,132	60,613
Prepaid expenses and other	3,614	2,031
Inventory	2,166	2,147
Current deferred tax asset	2,917	1,326
Total current assets	45,829	66,117
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,075,912	1,001,361
Unproved properties	41,182	49,443
Other property and equipment	981	900
Accumulated depreciation, depletion and amortization	(334,016)	(260,681)
Total property, plant and equipment, net	784,059	791,023
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	55,996	50,901
Other	1,967	2,263
Total other non-current assets	57,963	53,164
TOTAL ASSETS	$ 887,851	$ 910,304
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 105,613	$ 96,833
Current derivative liability	1,600	1,131
Current asset retirement obligation	2,708	1,315
Total current liabilities	109,921	99,279

NON-CURRENT LIABILITIES:		
Long-term debt	65,977	90,000
Deferred tax liability	98,456	105,956
Asset retirement obligations	23,827	22,019
Total non-current liabilities	188,260	217,975
Total liabilities	298,181	317,254
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 24,357,099 shares issued and 19,364,574 shares outstanding at June 30, 2014, 24,356,236 shares issued and 19,363,711 shares outstanding at December 31, 2013	962	962
Additional paid-in capital	230,876	228,644
Treasury shares at cost (4,992,525 shares at June 30, 2014 and December 31, 2013)	(119,180)	(119,180)
Retained earnings	477,012	482,624
Total shareholders' equity	589,670	593,050
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 887,851	$ 910,304

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

3

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(unaudited)		(unaudited)	
REVENUES:				
Oil and condensate sales	$ 38,340	$ 7,743	$ 73,440	$ 17,917
Natural gas sales	31,244	18,381	65,871	34,394
Natural gas liquids sales	8,835	4,584	19,365	10,184
Total revenues	78,419	30,708	158,676	62,495
EXPENSES:				
Operating expenses	11,576	10,687	22,629	20,472
Exploration expenses	10,853	5	37,784	134
Depreciation, depletion and amortization	39,901	10,230	74,303	20,724
Impairment and abandonment of oil and gas properties	1,371	767	16,566	767
General and administrative expenses	9,207	5,757	19,664	8,965
Total expenses	72,908	27,446	170,946	51,062
OTHER INCOME (EXPENSE):				
Gain from investment in affiliates (net of income taxes)	1,478	1,880	3,100	733
Interest expense	(737)	(13)	(1,405)	(25)
Loss on derivatives, net	(1,263)	—	(3,222)	—
Other income	(196)	9,722	(196)	9,875
Total other income (expense)	(718)	11,589	(1,723)	10,583
NET INCOME (LOSS) BEFORE INCOME TAXES	4,793	14,851	(13,993)	22,016
Income tax benefit (provision)	(212)	(3,495)	8,381	(6,791)
NET INCOME (LOSS)	$ 4,581	$ 11,356	$ (5,612)	$ 15,225
NET INCOME (LOSS) PER SHARE:				
Basic	$ 0.24	$ 0.75	$ (0.29)	$ 1.00
Diluted	$ 0.24	$ 0.75	$ (0.29)	$ 1.00
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	19,074,491	15,194,952	19,072,903	15,194,952
Diluted	19,130,012	15,194,952	19,072,903	15,194,952

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Six Months Ended June 30, 2014	2013
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (5,612)	$ 15,225
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	74,303	20,724
Impairment of natural gas and oil properties	15,592	767
Exploration expenses	36,755	(29)
Deferred income taxes	(6,901)	65
Gain from investment in affiliates	(4,770)	(1,128)
Stock-based compensation	2,115	—
Unrealized loss on derivative instruments	469	—
Changes in operating assets and liabilities:		
Decrease in accounts receivable and other receivables	15,649	1,778
Increase in prepaids	(1,692)	(157)
Increase (decrease) in accounts payable and advances from joint owners	2,050	(1,101)
Increase in other accrued liabilities	160	34
Decrease in income taxes receivable, net	58	11,673
Other	(328)	858
Net cash provided by operating activities	$ 127,848	$ 48,709
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (109,271)	$ (11,795)
Investment in affiliates	—	(14,916)
Distributions from affiliates	5,365	—
Net cash used in investing activities	$ (103,906)	$ (26,711)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 233,973	$ —
Repayments under credit facility	(257,996)	—
Proceeds from exercised options	118	—
Debt issuance costs	(37)	—

Net cash used in financing activities	$ (23,942)	$ —
NET INCREASE IN CASH AND CASH EQUIVALENTS	$ —	$ 21,998
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	79,487
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ 101,485

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(in thousands, except number of shares)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
	(unaudited)					
Balance at December 31, 2013	19,363,711	$ 962	$ 228,644	$ (119,180)	$ 482,624	$ 593,050
Exercise of stock options	4,081	—	118	—	—	118
Restricted shares activity	(3,218)	—	—	—	—	—
Stock-based compensation	—	—	2,114	—	—	2,114
Net income	—	—	—	—	(5,612)	(5,612)
Balance at June 30, 2014	19,364,574	$ 962	$ 230,876	$ (119,180)	$ 477,012	$ 589,670

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

6

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 natural gas and oil company. The Company’s business is to explore, develop, produce and acquire natural gas and oil properties in the shallow waters of the Gulf of Mexico ("GOM") and in the Gulf Coast, Texas and Rocky Mountain regions of the United States.

On October 1, 2013, the Company completed a merger with Crimson Exploration Inc. ("Crimson"), in an all-stock transaction (the "Merger") pursuant to which Crimson became a wholly-owned subsidiary of Contango.

The Company's operations are focused offshore in the GOM in water-depths of less than 300 feet as well as in long life resource plays in Southeast Texas (the Woodbine oil and liquids-rich play), South Texas (the Eagle Ford Shale and Buda oil and liquids-rich plays), and East Texas (the James Lime liquids-rich play and, under an improved natural gas price environment, the Haynesville/Mid-Bossier gas play). The Company believes these plays, and other formations in the same areas, provide significant long-term growth potential.

Additionally, the Company has (i) a 37% equity investment in Exaro Energy III LLC (“Exaro”) that is primarily focused on the development of proved natural gas reserves in a portion of the Jonah Field in Wyoming; (ii) leasehold positions and non-operated producing properties in Louisiana and Mississippi targeting the Tuscaloosa Marine Shale (“TMS”); (iii) operated properties producing from various conventional formations in various counties along the Texas Gulf Coast; (iv) operated producing properties in the Denver Julesburg Basin (“DJ Basin”) in Weld and Adams counties in Colorado, which the Company believes are prospective in the Niobrara Shale oil play; (v) approximately 93,000 net acres (80% working interest) in Wyoming, which the Company has the right to drill to earn , where the Company expects to soon initiate a horizontal drilling program, with hydraulic fractured completions, targeting multiple formations including the Mowry Shale, and approximately 18,000 new acquired net acres (50% working interest) in Fayette, Gonzalez, Caldwell and Bastrop counties, Texas on which the Company expects to soon initiate a similar program targeting multiple formations and (vi) six exploratory prospects in the shallow waters of the Gulf of Mexico.

The Company intends to grow reserves and production by developing its existing producing property base and by exploiting its unproved oil and liquids resource potential. The Company has developed a significant inventory of drilling opportunities on its existing property base that should provide multi-year reserve growth, and until sustained improvement is seen in natural gas prices, expects to concentrate drilling activity on further developing the oil and liquids-rich onshore assets in Southeast Texas, South Texas and the GOM. In 2014, the Company will focus on its crude oil and liquids-rich projects with a continuous drilling rig program in each of the Woodbine play in Madison and Grimes Counties, Texas, and the Buda play in Dimmit County, Texas. The Company's planned 2014 capital program also includes a number of other wells testing new formations in existing and new areas, including the Company’s newly acquired acreage.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information, pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”), including instructions to 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 audited consolidated financial statements and notes included in the Company’s Annual Report on Form 10-K/A for the year ended December 31, 2013 and Transition Report on Form 10-K for the transition period from July 1, 2013 to December 31, 2013. The consolidated results of operations for the six months ended June 30, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014.

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. Oil and gas exploration and development affiliates which are not controlled by the Company, such as Republic Exploration LLC ("REX"), are proportionately consolidated. Financial statements as of June 30, 2014 and December 31, 2013, and for the three and six months ended June 30, 2014 contained herein, include consolidated results of operations of both Contango and Crimson. Financial statements for the three and six months ended June 30, 2013 include only consolidated results of operations of Contango.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The most significant estimates include oil and gas revenues, income taxes, stock-based compensation, reserve estimates, impairment of natural gas and oil properties, valuation of derivatives, and accrued liabilities. Actual results could differ from those estimates.

Cash Equivalents

Cash equivalents are considered to be highly liquid investment grade investments having an original maturity of 90 days or less. As of June 30, 2014 and December 31, 2013, the Company had no cash or cash equivalents. Under the Company's policy, checks issued but not yet cleared through the bank are classified as accounts payable in the consolidated balance sheets. At June 30, 2014 and December 31, 2013, accounts payable included $19.3 million and $5.9 million, respectively, representing net outstanding checks that had not yet been presented for payment.

Impairment of Long-Lived Assets

When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future net cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows based on the Company's estimate of future natural gas and oil prices and operating costs and anticipated production from proved and probable reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair value. No impairment of proved properties was recognized for the three and six months ended June 30, 2014 or 2013.

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.

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

For the three and six months ended June 30, 2013, the Company recorded impairment expense of approximately $0.7 million related to unproved properties.

Net Income (Loss) Per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For the three months ended June 30, 2014, the weighted average incremental shares for stock options was 7,264 shares and the weighted average incremental for restricted stock was 48,257 shares. Potential dilutive securities, including stock options and non-vested restricted stock, have not been considered when their effect would be antidilutive. For the three months ended June 30, 2014, 94,914 shares were excluded from dilutive shares as they were antidilutive. For the six months ended June 30, 2014, 130,639 stock options and 287,792 restricted shares were excluded from the dilutive shares due to the loss for the period. For the three and six months ended June 30, 2013, the Company had no potentially dilutive securities.

Reclassifications

Certain reclassifications have been made to the amounts included in the consolidated financial statements as of December 31, 2013 and for the six months ended June 30, 2013, in order to conform to the presentation as of and for the six months ended June 30, 2014. These reclassifications were not material.

Subsidiary Guarantees

The Company filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Company may issue from time to time. Crimson, Crimson Exploration Operating, Inc., Contango Energy Company, Contango Operators, Inc., Contango Mining Company, Conterra Company, Contaro Company, Contango Alta Investments, Inc., Contango Venture Capital Corporation and any other of its future subsidiaries specified in the prospectus supplement, except for minor subsidiaries, (each a “Subsidiary Guarantor”) are Co-Registrants with the Company under the registration statement, and the registration statement also registered guarantees of debt securities by the Subsidiary Guarantors. The Subsidiary Guarantors are wholly-owned by the Company, either directly or indirectly, and any guarantee by the Subsidiary Guarantors will be full and unconditional. The 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 Company. The Company has one wholly-owned subsidiary that is inactive and one minor subsidiary which are not subsidiary guarantors. Finally, the 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 Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

Recent Accounting Pronouncements

In May 2014, the FASB and the International Accounting Standards Board ("IASB") jointly issued new accounting guidance for recognition of revenue. This new guidance replaces virtually all existing US GAAP and IFRS guidance on revenue recognition. The new guidance is effective for fiscal years beginning after December 15, 2016. This new guidance applies to all periods presented. Therefore, when the Company issues its financial statements on Forms 10-Q and 10-K for periods included in its year ended December 31, 2017, its comparative periods that are presented from the years ended December 31, 2015 and 2016, must be retrospectively presented in compliance with this new guidance. Early adoption is not allowed for US GAAP. The new guidance requires companies to make more estimates and use more judgment than under current accounting guidance. The Company is currently evaluating (i) the two allowed adoption methods to determine which method it plans to use for retrospective presentation of comparative periods and (ii) whether the implementation of this new guidance will have a material impact on the Company's consolidated financial position or results of operations for the periods presented.

In April 2014, the FASB issued amendments to guidance for reporting discontinued operations and disposals of components of an entity. The amended guidance requires that a disposal representing a strategic shift that has (or will have) a major effect on an entity's financial results or a business activity classified as held for sale should be reported as discontinued operations. The amendments also expand the disclosure requirements for discontinued operations and add new disclosures for individually significant dispositions that do not qualify as discontinued operations. The amendments are effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2014 (early adoption is permitted only for disposals that have not been previously reported). The implementation of the amended guidance is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. The Company is currently evaluating the provisions of ASU 2014-08 and assessing the impact, if any, it may have on its financial position and results of operations.

In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), revised its criteria related to internal controls over financial reporting from the originally established 1992 Internal Control - Integrated Framework with 2013 Internal Control - Integrated Framework. The modified framework provides enhanced guidance that ties control objectives to the related risk, enhancement of governance concepts, increased emphasis on globalization of markets and operations, increased recognition of use and reliance on information technology, increased discussion of fraud as it relates to internal control, changes of control deficiency descriptions, and that internal reporting is included in both financial and nonfinancial objectives. The revised framework is effective for interim and annual periods beginning after December 15, 2013. The Company plans to implement any changes required by the new COSO framework during the year ended December 31, 2014. Currently, the Company is evaluating the provisions of the revised framework and continues to assess the impact, if any, it may have on its internal control structure.

In February 2013, the FASB issued Accounting Standards Update No. 2013-04 Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (ASU 2013-04). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. U.S. GAAP does not include specific guidance on accounting for such obligations with joint and several liability, which has resulted in diversity in practice. The accounting update is effective for interim and annual periods beginning after December 15, 2013. The provisions of this accounting update did not have a material impact on its financial position or results of operations.

Further, management is closely monitoring the joint standard-setting efforts of the FASB and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2014 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, accounting for financial instruments, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time management is not able to determine the potential future impact that these standards will have, if any, on the Company's financial position, results of operations, or cash flows.

3. Merger with Crimson Exploration Inc.

On October 1, 2013, the Company completed the Merger with Crimson. The Merger was effected pursuant to an Agreement and Plan of Merger, dated as of April 29, 2013, by and among Contango, Crimson and a subsidiary of Contango (the “Merger Agreement”).

As a result of the Merger, each share of Crimson common stock was converted into 0.08288 shares of common stock of Contango, and the Company issued approximately 3.9 million shares of common stock in exchange for all of Crimson's outstanding capital stock, resulting in Crimson stockholders owning approximately 20.3% of the post-merger Contango.

The Merger was accounted for as a business combination in accordance with ASC 805 which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Crimson's results of operations are reflected in the Company's consolidated statement of operations, beginning October 1, 2013.

During the quarter ended June 30, 2014, the Company completed an analysis of Crimson’s asset retirement obligations as of the acquisition date. Based on this analysis, the Company recorded a measurement period adjustment of $2.5 million to increase the asset retirement obligations liability.

Crimson contributed revenues of $41.3 million and pre-tax income of $1.1 million to the Company for the three months ended June 30, 2014. Crimson contributed revenues of $78.4 million and pre-tax income of $7.1 million to the Company for the six months ended June 30, 2014. The following unaudited pro forma summary presents consolidated information of the Company as if the Merger had occurred on January 1, 2013 (in thousands):

	Pro forma Three Months Ended June 30, 2013 (Unaudited)	Pro forma Six Months Ended June 30, 2013 (Unaudited)
Revenue	$ 67,505	$ 123,388
Net income	$ 14,507	$ 16,163

The unaudited pro forma amounts have been calculated by applying the Company's accounting policies and adjusting the results of Crimson to reflect additional depletion that would have been charged assuming the fair value adjustment to oil and gas properties had been applied from January 1, 2013, together with the consequential tax effects. The pro forma depletion for the period was calculated based on the value of oil and gas properties acquired, giving effect to the fair value adjustments as a result of acquisition accounting and estimated depletion rate for each period. This depletion rate was calculated by dividing production for the period by the beginning of the period proved reserves. The combined historical depreciation, depletion and amortization expenses for the three and six months ended June 30, 2013 were increased by $0.3 million and $2.7 million, respectively.

The pro forma interest expense for each period presented was adjusted to reflect the results of the repayment of $175 million of Crimson's debt using cash available at the Merger date plus borrowings of $110.0 million under the new revolving credit facility with Royal Bank of Canada and other lenders (the “RBC Credit Facility”), as if such repayment had occurred on January 1, 2013, which reduced total combined interest expenses for the three and six months ended June 30, 2013 by $4.4 million and $10.6 million, respectively. The expense related to the amortization of the original issue discount on Crimson's debt was also eliminated for each period.

The pro forma net income was not adjusted for combined historical impairment charges of $0.8 million and $1.6 million, incurred by Crimson during the three and six months ended June 30, 2013, respectively.

Historical financial statements of Contango for the three and six months ended June 30, 2013 include approximately $2.3 million and $3.0 million of Merger related costs. These expenses are included in general and administrative expense in the Company's consolidated statements of income for the respective periods.

Pro forma net income for the three and six months ended June 30, 2013 does not include $5.7 million of stock-based compensation expenses related to the vesting of Crimson stock options on October 1, 2013 as a result of the Merger, amortization of debt issuance cost of $0.8 million, amortization of the remaining balance of debt discount of $3.7 million for Crimson debt as of the date of the Merger, and other Merger related costs, including $2.8 million bankers success fees, which were recognized in Crimson's results of operations for the period October 1, 2013, which is not included in consolidated financial statements of the Company. Pro forma net income also does not include the benefit related to the release of a $10.2 million deferred tax asset valuation allowance in relation to the Merger recognized in purchase accounting. Although such expenses relate to the Merger, they do not represent recurring expenses and, therefore, are not included in the pro forma results of operations.

4. Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value as of June 30, 2014. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have been no transfers between Level 1, Level 2 or Level 3.

Fair value information for financial assets and liabilities was as follows as of June 30, 2014 (in thousands):

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$ —	$ —	$ —	$ —
Commodity price contracts - liabilities	$ (1,600)	$ —	$ (1,600)	$ —

Derivatives listed above include swaps and collars that are carried at fair value. The Company records the net change in the fair value of these positions in "Loss on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 5 - "Derivative Instruments" for additional discussion of derivatives.

As of June 30, 2014, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a 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 have been 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 RBC Credit Facility approximates carrying value because the facility interest rate approximates current market rates and is re-set at least every three months. See Note 9 - "Long-Term Debt" for further information.

5. Derivative Instruments

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

As of June 30, 2014, the Company's crude oil and natural gas derivative positions consisted of swaps and costless put/call "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 sold call, which establishes a maximum price the Company will receive for the volumes under contract, and a purchased put that establishes a minimum price.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The counterparties to the Company's current derivative contracts are lenders or affiliates of lenders in the RBC Credit Facility. The Company does not post collateral, nor is exposed to potential margin calls, under any of these contracts as they are secured under the RBC Credit Facility.

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

The following derivative contracts were in place at June 30, 2014, (fair value in thousands):

Commodity	Period	Derivative	Volume/Month (1)	Price/Unit (2)	Fair Value
Crude Oil	Jul 2014-Dec 2014	Swap	7,500 Bbls	$102.10 (4)	$ (409)
Crude Oil	Jul 2014-Dec 2014	Swap	6,000 Bbls	$106.40 (4)	(174)
Crude Oil	Jul 2014-Sep 2014	Swap	13,000 Bbls	$92.57 (3)	(461)
Crude Oil	Oct 2014-Dec 2014	Swap	11,000 Bbls	$90.61 (3)	(374)
Natural Gas	Jul 2014-Dec 2014	Collar	120,000 MMBtu	$4.00 - $4.415 (5)	(132)
Natural Gas	Jul 2014-Dec 2014	Collar	42,500 MMBtu	$3.75 - $4.60 (5)	(33)
Natural Gas	Jul 2014-Dec 2014	Collar	42,500 MMBtu	$3.50 - $5.00 (5)	(17)
		Total net fair value of derivative instruments			$ (1,600)

(1) Average volume per month for the remaining contract term
(2) Average price per unit for the remaining contract term
(3) Commodity derivative based on NYMEX West Texas Intermediate crude oil prices
(4) Commodity derivative based on Brent crude oil prices
(5) Commodity derivative based on Henry Hub NYMEX natural gas prices

There was no activity or outstanding derivative contracts during the three or six months ended June 30, 2013.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of June 30, 2014 (in thousands):

	Gross	Netting (1)	Total
Assets	$ —	$ —	$ —
Liabilities	$ (1,600)	$ —	$ (1,600)

(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 six months ended June 30, 2014 (in thousands):

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

There were no gains or losses related to derivative instruments for the three or six months ended June 30, 2013.

6. Stock-Based Compensation

As of June 30, 2014, the Company had in place a stock-based compensation program which allows for stock options and/or restricted stock to be awarded to officers, directors, consultants and employees as a performance-based award or granted upon initial employment as part of their overall compensation package. This program includes (i) the Company's original 2009 Equity Compensation Plan (the “2009 Plan”); and (ii) the Crimson 2005 Stock Incentive Plan (the “2005 Plan” or "Crimson Plan") adopted in conjunction with the Merger. In April 2014 the board of directors approved an Amended and Restated 2009 Incentive Compensation Plan, which amends and restates the 2009 Plan and includes both cash and equity parts of incentive compensation. This plan was approved by the Company's shareholders at the Annual Shareholders Meeting in May 2014.

Stock Options

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the six months ended June 30, 2014 and 2013, there were no excess tax benefits recognized.

Compensation expense related to employee stock option grants are recognized over the stock option’s vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. No stock options were granted during the six months ended June 30, 2014 or 2013.

During the six months ended June 30, 2014, 4,081 stock options were exercised and 387 stock options were forfeited by terminated employees. No stock options were exercised or forfeited during the six months ended June 30, 2013.

Restricted Stock

During the six months ended June 30, 2014, the Company granted 3,700 shares of restricted common stock under the 2009 Plan to newly hired and promoted employees as part of their compensation package, which vest over a four-year period. The weighted average fair value of the restricted shares granted during the six months ended June 30, 2014, was $45.96 with a total fair value of approximately $170 thousand after adjustment for an estimated weighted average forfeiture rate of 5.6%. Approximately 1.2 million shares remain available for grant under the 2009 Plan and the Crimson Plan as of June 30, 2014.

During the six months ended June 30, 2014, 6,918 restricted shares were forfeited by terminated employees. The aggregate intrinsic value of restricted shares forfeited during the six months ended June 30, 2014 was approximately $324 thousand.

During the six months ended June 30, 2014, the Company recognized approximately $2.1 million in stock compensation expense for the vesting of restricted shares previously granted to its officers, employees and directors. As of June 30, 2014, an additional $9.2 million of compensation expense will be recognized over the remaining weighted-average vesting period of 2.7 years.

On July 8, 2014, the Company granted a total of 15,672 shares of restricted stock to the directors of the Company, as a result of their re-election to the Board at the annual shareholder meeting, pursuant to the Company’s Director Compensation Plan.

7. Other Financial Information

The following table provides additional detail for accounts receivable, prepaids and other, and accounts payable and accrued liabilities which are presented on the consolidated balance sheets (in thousands):

	June 30, 2014	December 31, 2013
Accounts Receivable:		
Trade receivable	$ 28,287	$ 42,196
Receivable for Alta Resources distribution	1,993	7,358
Joint interest billing	2,753	5,172
Income taxes receivable	1,811	4,293
Other receivables	2,885	2,172
Allowance for doubtful accounts	(597)	(578)
Total Accounts Receivable	$ 37,132	$ 60,613
Prepaid Expenses and Other:		
Prepaid insurance	$ 3,024	$ 1,113
Other	590	918
Total Prepaid Expenses and Other	$ 3,614	$ 2,031
Accounts Payable and Accrued Liabilities:		
Royalties and revenue payable	$ 42,952	$ 44,933
Accrued exploration and development	24,608	17,803
Trade payable	15,588	11,589
Advances from partners	8,121	6,538
Accrued general and administrative expenses	10,081	10,872
Other accounts payable and accrued liabilities	4,263	5,098
Total Accounts Payable and Accrued Liabilities	$ 105,613	$ 96,833

Included in the table below is supplemental information about cash and non-cash transactions during the six months ended June 30, 2014 and 2013 (in thousands):

	Six Months Ended June 30, 2014	2013
Cash payments:		
Interest payments	$ 1,531	$ 25
Income tax payments (receipts)	$ 132	$ (3,658)

Total capital expenditures incurred by the Company for the six months ended June 30, 2014 and 2013 were approximately $117.2 million and $9.9 million, respectively. Of these amounts, $8.0 million and $(0.9) million are changes in a non-cash accrual for capital expenditures incurred but not yet paid for the six months ended June 30, 2014 and 2013, respectively.

8. Investment in Exaro Energy III LLC

In April 2012, the Company entered into a Limited Liability Company Agreement (the “LLC Agreement”) in connection with the formation of Exaro. Pursuant to the LLC Agreement, as amended, the Company committed to invest up to $67.5 million in Exaro for an ownership interest of approximately 37%. The aggregate commitment of all the Exaro partners is approximately $183 million. As of December 31, 2013, the Company had invested approximately $46.9 million. No additional contributions were made during the six months ended June 30, 2014.

The following table (in thousands) presents condensed balance sheet data for Exaro as of June 30, 2014 and December 31, 2013. The balance sheet data was derived from the Exaro balance sheet as of June 30, 2014 and December 31, 2013 and was not adjusted to represent the Company's percentage of ownership interest in Exaro. The Company's share in the equity of Exaro at June 30, 2014 was approximately $55.3 million.

	June 30, 2014	December 31, 2013
Current assets	$ 19,487	$ 30,284
Non-current assets:		
Net property and equipment	229,157	182,226
Restricted cash escrow account	18,014	8,732
Other non-current assets	1,130	1,103
Total non-current assets	248,301	192,061
Total assets	$ 267,788	$ 222,345
Current liabilities	$ 11,285	$ 13,717
Non-current liabilities:		
Long-term debt	105,000	70,000
Other non-current liabilities	1,054	923
Total non-current liabilities	106,054	70,923
Members' equity	150,449	137,705
Total liabilities & members' equity	$ 267,788	$ 222,345

The following table (in thousands) presents the condensed results of operations for Exaro for the three and six months ended June 30, 2014 and 2013. The results of operations for the three and six months ended June 30, 2014 and 2013 were derived from Exaro's financial statements for the respective periods. The income statement data below was not adjusted to represent the Company's ownership interest but rather reflects the results of Exaro as a company. The Company's share in Exaro's results of operations recognized for the three months ended June 30, 2014 and 2013 was a gain of $1.5 million, net of tax expense of $(0.8) million, and a gain of $1.9 million, net of tax expense of $(1.0) million, respectively. The Company's share of Exaro's results of operations recognized for the six months ended June 30, 2014 and 2013 was a gain of $3.1 million, net of tax expense of $(1.7) million, and a gain of $0.7 million, net of tax expense of $(0.4) million, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Oil and natural gas sales	$ 19,951	$ 12,707	$ 42,290	$ 20,486
Other gain (loss)	(17)	4,032	(1,992)	549
Less:				

Lease operating expenses	5,180	3,931	11,412	6,145
Depreciation, depletion, amortization & accretion	6,457	3,492	12,126	5,788
General & administrative expense	1,091	1,080	1,950	1,890
Income from continuing operations	7,206	8,236	14,810	7,212
Net interest expense	(1,048)	(402)	(1,966)	(660)
Net income	$ 6,158	$ 7,834	$ 12,844	$ 6,552

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

9. Long-Term Debt

RBC Credit Facility

As of June 30, 2014 and December 31, 2013, the Company had approximately $66.0 million and $90.0 million, respectively, outstanding under the RBC Credit Facility and $1.9 million and $1.9 million, respectively, in outstanding letters of credit. As of June 30, 2014, borrowing availability under the RBC Credit Facility was $207.1 million.

The RBC Credit Facility is collateralized by a lien on substantially all the assets of the Company and its subsidiaries, including a security interest in the stock of Contango’s subsidiaries and a security interest in the Company’s oil and gas properties.

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

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require the maintenance of a minimum current ratio and a maximum leverage ratio. As of June 30, 2014, the Company was in compliance with all covenants under the RBC Credit Facility. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at June 30, 2014 and December 31, 2013 was 1.9680% and 2.1875%, respectively. The RBC Credit Facility matures on October 1, 2017, at which time any outstanding balances will be due.

Amegy Bank Credit Facility

The RBC Credit Facility replaced the Company's $40 million credit facility with Amegy Bank. Interest expense under the Amegy Credit Agreement for the three and six months ended June 30, 2013 was approximately $13 thousand and $25 thousand, respectively.

10. Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Current tax provision (benefit):				
Federal	$ —	$ 4,306	$ (524)	$ 6,342
State	122	1,633	713	2,173
Total	$ 122	$ 5,939	$ 189	$ 8,515
Deferred tax provision (benefit):				
Federal	$ 1,378	$ (2,089)	$ (6,426)	$ (1,770)
State	(493)	657	(475)	441
Total	$ 885	$ (1,432)	$ (6,901)	$ (1,329)
Total tax provision (benefit):				
Federal	$ 1,378	$ 2,217	$ (6,950)	$ 4,572
State	(371)	2,290	238	2,614
Total	$ 1,007	$ 4,507	$ (6,712)	$ 7,186
Included in gain (loss) from investment in affiliates	$ 795	$ 1,012	$ 1,669	$ 395
Total income tax provision (benefit)	$ 212	$ 3,495	$ (8,381)	$ 6,791

The effective tax rate for the three and six months ended June 30, 2014 varies from the statutory rate primarily due to the effect of state income taxes, offset by the permanent differences related to deductible Merger transaction costs and additional depletion deductions for state taxes resulting from the return to provision adjustments for federal and state taxes. The effective tax rate for the three and six months ended June 30, 2013 varied from the statutory rate due to non-taxable income related to life insurance proceeds partially offset by state income taxes and non-deductible merger related expenses.

11. Related Party Transactions

Juneau Exploration L.P.

Effective January 1, 2013, the Company and Juneau Exploration L.P. ("JEX") entered into a First Right of Refusal Agreement (the "First Right Agreement"). Under the First Right Agreement, JEX granted a first right of refusal to Contango to purchase any exploration prospects generated and recommended by JEX. Pursuant to the First Right Agreement, JEX was to be paid an annual fee of $0.5 million, which approximates the costs incurred by JEX for its support to the Company in the areas of operations, engineering and land functions. JEX and its employees continued to be eligible to receive overriding royalty interests, carried interests and certain back-in rights. The First Right Agreement was terminated effective as of March 31, 2013.

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

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

Olympic Energy Partners

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

JEX, affiliates of JEX, and Olympic have historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest ("WI"), net revenue interest ("NRI"), and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX, excluding Mr. Juneau, except where otherwise noted. Olympic last participated with the Company in the drilling of wells in March 2010, and its ownership in Company-operated wells is limited to its Dutch and Mary Rose wells.

Republic Exploration LLC

In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of Republic Exploration LLC ("REX"), an entity owned 34.4% by JEX, 32.3% by Contango and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest, net revenue interest and describe when such interests are earned, as well as allocate an overriding royalty interest of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

As of June 30, 2014, Olympic, JEX, REX and JEX employees owned the following interests in the Company's offshore wells.

	Olympic		JEX		REX		JEX Employees
	WI	NRI	WI	NRI	WI	NRI	ORRI
Dutch #1 - #5	3.53%	2.84%	1.88%	1.51%	—%	—%	2.02%
Mary Rose #1	3.61%	2.70%	2.01%	1.51%	—%	—%	2.79%
Mary Rose #2 - #3	3.61%	2.58%	2.01%	1.44%	—%	—%	2.79%
Mary Rose #4	2.34%	1.70%	1.31%	0.95%	—%	—%	1.82%

Mary Rose #5	2.56%	1.87%	1.43%	1.04%	—%	—%	1.54%
Ship Shoal 263	—%	—%	—%	—%	—%	—%	3.33%
Vermilion 170	—%	—%	4.30%	3.35%	12.50%	9.74%	3.33%

Prior to exercising a preferential right in December 2013, Olympic and JEX had the following lower WI and NRI in Dutch #1-#5 wells:

	Olympic		JEX	
	WI	NRI	WI	NRI
Dutch #1 - #5	3.02%	2.42%	1.61%	1.29%

During the three and six months ended June 30, 2014, Mr. Romano earned $26 thousand and $52 thousand, respectively, for his service as a director of the Company. During the three months ended March 31, 2014, Mr. Juneau earned $12 thousand for his service as a director of the Company, and on March 19, 2014, Mr. Juneau resigned from the board of directors. During the three and six months ended June 30, 2013, Mr. Juneau earned $28 thousand and $56 thousand, respectively, for his service as a director of the Company.

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

On July 8, 2014, the Company granted 2,612 shares of restricted stock to Mr. Romano as part of his board of director compensation.

As of June 30, 2014, Mr. Romano was entitled to receive a bonus of $4.0 million as a result of the merger with Crimson, as he continued his service to the Company through June 30, 2014. Approximately $1.3 million and $2.6 million related to this bonus is included in general and administrative expenses for the three and six months ended June 30, 2014, respectively. This bonus was paid in July 2014.

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

Below is a summary of payments received from (paid to) Olympic, JEX and REX in the ordinary course of business in the Company’s capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types of payments with other well owners (in thousands):

	Three months ended June 30,					
	2014			2013		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$ (2,265)	$ (1,501)	$ (672)	$ (1,755)	$ (962)	$ (9)
Joint interest billing receipts	212	132	111	308	553	994

	Six months ended June 30,					
	2014			2013		
	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$ (4,212)	$ (2,812)	$ (1,346)	$ (3,405)	$ (2,157)	$ (859)
Joint interest billing receipts	282	157	156	594	750	1,109

Below is a summary of payments received from (paid to) Olympic, JEX and REX as a result of specific transactions between the Company, Olympic, JEX and REX. While these payments are in the ordinary course of business, the Company did not have similar transactions with other well owners (in thousands):

	Three months ended June 30,					
	2014			2013		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$ (54)	$ (29)	$ —	$ —	$ (743)	$ (1)
Rent received for sublease	—	43	—	—	—	—

	Six months ended June 30,					
	2014			2013		
	Olympic	JEX	REX	Olympic	JEX	REX
Reimbursement of certain costs	$ (54)	$ (29)	$ —	$ —	$ (1,069)	$ (5)
Rent received for sublease	—	66	—	—	—	—

As of June 30, 2014 and December 31, 2013, the Company's consolidated balance sheets reflected the following balances (in thousands):

	June 30, 2014			December 31, 2013		
	Olympic	JEX	REX	Olympic	JEX	REX
Accounts receivable:						
Joint interest billing	$ 28	$ 130	$ 50	$ 34	$ 87	$ 116
Accounts payable:						
Royalties and revenue payable	(1,522)	(972)	(347)	(1,293)	(877)	(466)

Oaktree Capital Management L.P.

As of June 30, 2014, Oaktree Capital Management L.P. ("Oaktree"), through various funds, owned approximately 6.7% of the Company's stock. On October 1, 2013, following the closing of the Merger, Mr. James Ford, a Manging Director and Portfolio Manager within Oaktree, was elected to the Company's board of directors. Mr. Ford was previously a member of Crimson's board of directors from February 2005 until the closing of the Merger.

As part of Mr. Ford's director compensation, all cash and equity awards payable to Mr. Ford, are instead granted to an affiliate of Oaktree. During the three and six months ended June 30, 2014, the affiliate of Oaktree earned $13 thousand and $32 thousand in cash as a result of Mr. Ford's board participation, and the Company recognized compensation expense of approximately $18 thousand and $36 thousand related to the 1,622 shares of restricted stock granted to an affiliate of Oaktree in December 2013. These shares vest 100% on the one-year anniversary of the date of the grant.

On July 8, 2014, the Company granted 2,612 shares of restricted stock to an affiliate of Oaktree as part of Mr. Ford’s board of director compensation.

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.

Mineral interest owners in South Louisiana filed suit against a subsidiary of the Company and several co-defendants in June 2009 in the 31st Judicial District Court situated in Jefferson Davis Parish, Louisiana alleging failure to act as a reasonably prudent operator, failure to explore, waste, breach of contract, etc. in connection with two wells located in Jefferson Davis Parish. Many of the alleged improprieties occurred prior to the Company’s ownership of an interest in the wells at issue, although the Company may have assumed liability otherwise attributable to its predecessors-in-interest through the acquisition documents relating to the acquisition of the Company’s interest in these wells. The damages most recently alleged by the plaintiffs are approximately $13.4 million. The Company and its co-defendants are vigorously defending this lawsuit and believe that they have meritorious defenses. The Company and its co-defendants obtained a favorable judgment from the trial court following a trial, but the judgment is being appealed by the plaintiffs. A companion case involving the same claims, wells, etc. was filed in the same court on April 19, 2013 on behalf of additional mineral interest owners.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by us or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. The trial court has granted plaintiff's motion for partial summary judgment as to liability (but not damages). While preserving the Company’s right to appeal as to liability, the Company recently entered into a partial judgment with the plaintiff which establishes the amount of damages recoverable by the plaintiff, if it ultimately prevails in this case, at approximately $5.3 million (which excludes pre-judgment interest although the plaintiff may appeal the trial court’s ruling that interest is not owed). The Company is vigorously defending this lawsuit, believe that it has meritorious defenses and intend to appeal the aforementioned decision.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson “A” Unit in Liberty County in Texas. This case was subsequently transferred to 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. In their initial pleading the plaintiff alleges damages in excess of $6.0 million, which is generally in line with amounts received on its undisputed 1/16th mineral interest as of the date the suit was filed. As of July 31, 2014, the Plaintiff had received approximately $9.3 million in royalties in respect of its undisputed interest. The Company is vigorously defending this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

In connection with the Merger, several class action lawsuits have been brought by Crimson stockholders in Delaware Chancery Court seeking damages and injunctive relief including, among other things, compensatory damages and costs and disbursements relating to the lawsuits. Various combinations of the Company, certain subsidiaries of the Company, members of Crimson's pre-merger board of directors, members of Crimson's pre-merger management team and Oaktree Capital Management L.P. have been named as defendants in these lawsuits. The Delaware lawsuits have been consolidated into a single action referred to as In Re: Crimson Exploration Inc. Stockholder Litigation; C.A. 8541-VCP. Additionally, on July 13, 2013, a separate and similar complaint was filed in the District Court of Harris County Texas, in the matter of Fisichella Family Trust v. Crimson Exploration Inc. It is possible that additional similar lawsuits may be filed.

The merger-related lawsuits allege, among other things, that Crimson's board of directors failed to take steps to obtain a fair price, failed to properly value Crimson, failed to protect against alleged conflicts of interest, failed to conduct a reasonably informed evaluation of whether the transaction was in the best interests of stockholders, failed to fully disclose all material information to stockholders, acted in bad faith and for improper motives, engaged in self-dealing, discouraged other strategic alternatives, took steps to avoid competitive bidding, and agreed to allegedly unreasonable deal protection mechanisms, including the no-shop, fiduciary-out provisions and termination fee. The lawsuits also allege that Contango and certain other defendants aided and abetted the other defendants in violating duties to the Crimson stockholders. The known plaintiffs in these lawsuits collectively owned a very small percentage of the total outstanding shares of Crimson common stock at the time of the Merger, which was approved by Contango's pre-merger shareholders (89% of outstanding shares and 99% of voted shares were voted in favor of the Merger) and Crimson's pre-merger shareholders (69% of outstanding shares and 88% of voted shares were voted in favor of the Merger). The Company believes that these merger-related lawsuits are without merit and is contesting them vigorously.

In February 2011, a subsidiary of the Company and certain of its working interest partners and insurance carriers brought suit against a marine construction, dredging and tunneling company and an instrumentality of the United States of America in the U.S. District Court for the Southern District of Texas - Houston Division seeking monetary damages for damage to an offshore pipeline which was struck by a dredge. Following a bench trial in December 2013, the Company and its co-defendants obtained a favorable judgment from the trial court, but the judgment is being appealed by the defendants.

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 has maintained an officers and directors liability insurance policy for Crimson former directors and officers and has made a claim under the policy for coverage of these merger related lawsuits.

Available Information

General information about us can be found on our website at www.contango.com. Our Annual Report on Form 10-K/A and Transition Report on Form 10-K, Quarterly Reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission ("SEC"). We are not including the information on our website as a part of, or incorporating it by reference into, this Report.

Cautionary Statement about Forward-Looking Statements

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

- our financial position;
- our business strategy, including outsourcing;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- natural gas and oil price volatility;
- operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and natural gas processing facilities;
- the risks associated with acting as the operator in drilling deep high pressure and temperature wells, including well blowouts and explosions;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which we have made a large capital commitment relative to the size of our capitalization structure;
- the timing and successful drilling and completion of natural gas and oil wells;
- availability of capital and the ability to repay indebtedness when due;
- availability and cost of rigs and other materials and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures, and other risks;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;

- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals;
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements; and
- ability to obtain insurance coverage on commercially reasonable terms.

Any of these factors and other factors contained 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, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. All forward-looking statements speak only as of the date of this report.

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

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and the accompanying notes and other information included elsewhere in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K/A for the year ended December 31, 2013 and Transition Report on Form 10-K for the transition period from July 1, 2013 to December 31, 2013, previously filed with the Securities and Exchange Commission ("SEC").

Overview

Contango is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development, exploitation and production of crude oil and natural gas offshore in the shallow waters of the Gulf of Mexico (“GOM”) and in the Gulf Coast, Texas and Rocky Mountain regions of the United States.

On October 1, 2013, we completed a merger with Crimson Exploration Inc. (“Crimson”), in an all-stock transaction (the “Merger") pursuant to which Crimson became a wholly-owned subsidiary of Contango. As a result of the Merger, each share of Crimson common stock was converted into 0.08288 shares of common stock of Contango. As a result, we issued approximately 3.9 million shares of common stock in exchange for all of Crimson's outstanding capital stock, resulting in Crimson stockholders owning approximately 20.3% of post-Merger Contango. We also assumed $235.4 million in debt, including accrued interest and repayment premium, and issued 135,898 options in exchange for the outstanding options held by Crimson employees.

The Merger qualified as a tax-free reorganization for U.S. federal income tax purposes, so that none of Contango, Crimson, or any of their respective stockholders recognized any gain or loss in the Merger, except that Crimson's stockholders may have recognized a gain or loss with respect to cash received in lieu of fractional shares of Company common stock.

On October 1, 2013 the Company's board of directors approved a change in fiscal year end from June 30 to December 31. On March 3, 2014, we filed a Form 10-K which covered the transition period of July 1, 2013 through December 31, 2013, which included six months of Contango activity (July - December) and three months of post-merger Crimson activity (October - December). We also filed the Annual Report on Form 10-K/A to present the the financial statements of the Company on a calendar year basis for each of the three years in the period ended December 31, 2013. This Form 10-Q presents our information for the three and six months ended June 30, 2014 and 2013 based on a new year-end date of December 31. Unless otherwise noted, all references to "years" in this report refer to the twelve-month periods ended December 31 of each year.

We have historically focused our operations in the GOM, but our recent merger with Crimson has given us access to lower risk, long life resource plays in Southeast Texas (the Woodbine oil and liquids-rich play), in South Texas (the Eagle Ford Shale and Buda oil and liquids-rich plays) and in East Texas (the James Lime liquids-rich play, and under an improved natural gas price environment, the Haynesville/Mid-Bossier gas play). We believe these plays, and other formations in the same areas, provide long-term growth potential.

Additionally, we have (i) a 37% equity investment in Exaro Energy III LLC ("Exaro") that is primarily focused on the development of proved natural gas reserves in a portion of the Jonah Field in Wyoming; (ii) non-operated producing properties in Louisiana and Mississippi targeting the Tuscaloosa Marine Shale ("TMS"); (iii) operated properties producing from various conventional formations in various counties along the Texas Gulf Coast; (iv) operated producing properties in the Denver Julesburg Basin ("DJ Basin") in Weld and Adams counties in Colorado, which we believe are prospective in the Niobrara Shale oil play; (v) approximately 93,000 net acres (80% working interest) in Wyoming, which we have the right to drill to earn, where we expect to soon initiate a horizontal drilling program, with hydraulic fractured completions, targeting multiple formations including the Mowry Shale, and approximately 18,000 newly acquired net acres (50% working interest) in Fayette, Gonzalez, Caldwell and Bastrop counties, Texas on which we expect to soon initiate a similar program targeting multiple formations and (vi) six exploratory prospects in the shallow waters of the GOM.

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

We intend to grow reserves and production by developing our existing producing property base and by exploiting our unproved oil/liquids resource potential. We have developed a significant inventory of quality drilling opportunities on our existing property base that we believe should position us for multiyear reserve growth, and until sustained improvement is seen in natural gas prices, expect to concentrate drilling activity on further developing our oil and liquids-rich onshore assets in Southeast Texas, South Texas and the GOM. In 2014, we will focus on our inventory of crude oil and liquids-rich projects with rig programs in the Woodbine play in Madison and Grimes Counties, Texas, the Buda play in Dimmit County, Texas and the James Lime play in San Augustine County, Texas. We also currently plan to drill a number of other wells testing new formations in existing and new areas, including our newly acquired acreage.

We will continue to monitor expanding industry activity in the oil-weighted TMS and in the Niobrara Shale to determine the future potential and strategy for optimizing value in each play prior to committing significant drilling capital.

Summary Production Information

Our production for the three months ended June 30, 2014 was approximately 59% offshore and 41% onshore, and 64% natural gas and 36% oil and natural gas liquids. Our production for the three months ended June 30, 2013 was 100% offshore, and approximately 78% natural gas and 22% oil and natural gas liquids.

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

	Three Months Ended				
	June 30, 2013	September 30, 2013	December 31, 2013	March 31, 2014	June 30, 2014
Offshore GOM					
Dutch and Mary Rose	57.2	61.7	59.1	66.7	60.9
Vermilion 170	4.0	9.6	9.6	9.0	7.2
Other offshore (1)	1.0	0.7	0.8	0.4	0.6
Southeast Texas (2)	—	—	24.3	26.4	27.1
South Texas (2)	—	—	14.7	12.6	16.0
Other (2) (3)	—	—	1.7	2.4	4.2
	62.2	72.0	110.2	117.5	116.0

(1) The "Other offshore" line includes Ship Shoal 263.

(2) "Southeast Texas", "South Texas" and "Other" production are not included in the table above for periods prior to the quarter ended December 31, 2013, as a result of acquiring these producing properties effective October 1, 2013 due to the Merger.

(3) The "Other" line includes onshore wells in the East Texas and Rocky Mountain regions for the quarters ended December 31, 2013, March 31, 2014, and June 30, 2014.

The table below sets forth our pro forma net daily production data in Mmcfed from our fields for each of the periods indicated as if Merger took place on January 1, 2013:

	Pro forma Three Months Ended				
	June 30, 2013	September 30, 2013	December 31, 2013 (1)	March 31, 2014 (1)	June 30, 2014 (1)
Offshore GOM	62.2	72.0	69.5	76.1	68.7
Southeast Texas (2)	27.9	25.4	24.3	26.4	27.1
South Texas (2)	14.2	13.0	14.7	12.6	16.0
Other (2)	2.1	1.9	1.7	2.4	4.2
	106.4	112.3	110.2	117.5	116.0

(1) Production for the quarters ended December 31, 2013, March 31, 2014, and June 30, 2014 include historical production of the combined company post-merger.

(2) Production for Southeast Texas, South Texas and Other for the periods prior to October 1, 2013 represent historical production of Crimson Exploration Inc. as derived from its quarterly reports on Form 10-Q for the respective periods.

Offshore Gulf of Mexico

Dutch and Mary Rose Field

We operate five federal wells located at Eugene Island 10 (“Dutch”) and five state wells located in adjacent state of Louisiana waters (“Mary Rose”). These ten wells produce to a Company-owned and operated production platform at Eugene Island 11. While we do not hold a lease for the Eugene Island 11 block, this does not impact our ability to operate our facilities located on that block. Operators in the Gulf of Mexico may place platforms and facilities on any location without having to own the lease, provided that permission and proper permits from the Bureau of Safety and Environmental Enforcement (“BSEE”) have been obtained. We have obtained such permission and permits. We installed our facilities at Eugene Island 11 because that was the optimal gathering location in proximity to our wells and marketing pipelines.

From this platform we are able to access two separate markets which minimizes downtime risk and provides the ability to select the best sales price. Oil and gas production can flow via a TC Offshore (formerly ANR) pipeline to third-party owned and operated onshore processing facilities near Patterson, Louisiana. Alternatively, gas can flow to the American Midstream (Seacrest), LP pipeline via our 8” pipeline, which has been designed with a capacity of 80 Mmcfd, and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. Condensate can also flow via an ExxonMobil Pipeline Company pipeline to onshore markets and multiple refineries.

Based on normal production decline, a turbine type compressor of sufficient capacity to service all ten of our Dutch and Mary Rose wells was installed at the platform in July 2014. As of June 30, 2014, we had incurred approximately $8.8 million to design and build the compressor and have budgeted an additional $1.2 million for the installation in the third quarter of 2014. We plan to place our Dutch and Mary Rose wells on central compression at the Eugene Island 11 platform in the third quarter 2014.

In December 2013, we exercised a preferential right and purchased an additional 7.84% working interest and 6.53% net revenue interest in the five Contango-operated Dutch wells from an independent oil and gas company for approximately $15 million, after purchase price adjustment. Net production from our Dutch and Mary Rose wells for the quarter ended June 30, 2014 was approximately 60.9 Mmcfed, compared to 57.2 Mmcfed for the 2013 quarter. The increase in production from this field during the three months ended June 30, 2014 is mainly attributable to the additional working interest acquired in December 2013.

Vermilion 170 Field

We operate one well at Vermilion 170 which flows to a Company-owned and operated production platform at the same location. In January 2013, sustained casing pressure was identified between the production tubing and the production casing at our Vermilion 170 well. Well production was shut-in and the original tubing was successfully removed. Operations were conducted to replace the tubing and restore the well to production in June 2013. This shut-in resulted in a significantly lower production during the quarter ended June 30, 2013. Net production from this well for the quarter ended June 30, 2014 was approximately 7.2 Mmcfed, compared to 4.0 Mmcfed in the 2013 quarter.

Operating expenses for the six months ended June 30, 2013 include approximately $11.4 million related to workover expenses for this well, net to the Company.

Other (Offshore)

Our Ship Shoal 263 and South Timbalier 17 fields have been included in "Other Offshore". The Company operates one well at Ship Shoal 263, which produces to a Company-owned and operated production platform at the same location.

On July 30, 2013, we spud our South Timbalier 17 prospect in state of Louisiana waters, and on August 22, 2013, we announced a successful well at a total measured depth of 11,400 feet. We completed the well, installed production facilities and commenced production in July 2014. Net costs incurred to drill, complete and bring this well to full production status were $13.5 million as of June 30, 2014. We have a 75% working interest (53.3% net revenue interest) before payout and a 59.3% working interest (42.1% net revenue interest) after payout.

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

The interests above include our ownership interest in Republic Exploration LLC ("REX"), an entity owned 34.4% by JEX, 32.3% by Contango and 33.3% by a third party. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant's working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. In his capacity as sole manager of the general partner of JEX, Mr. Brad Juneau also controls the activities of REX. The Company proportionately consolidates its interest in REX in its consolidated financial statements.

Other Offshore Activities

During the year ended December 31, 2013, the Company was awarded three lease blocks, Eugene Island 23, Ship Shoal 52 and Ship Shoal 59, by the Bureau of Ocean Energy Management ("BOEM"), which were bid at the Central Gulf of Mexico Lease Sale 227 held on March 20, 2013. We currently hold 16 offshore lease blocks.

Onshore Properties

Our onshore areas of operations are concentrated on oil and liquids-rich unconventional plays, with year-to-date activity for 2014 consisting primarily of:

Southeast Texas (Woodbine)

During the quarter ended June 30, 2014, we brought two operated gross wells (1.5 net) on production that were spud in the first quarter of 2014, and an additional two gross wells (1.4 net) that were spud and completed during the second quarter. In total, seven wells were brought on production in the Woodbine formation for the six months ended June 30, 2014. We will continue our focus on further developing our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous one to two rig program planned for the rest of 2014. We have a multi-year inventory of potential drilling locations on our approximate 19,000 net acre position in Madison and Grimes counties, which we believe include the Woodbine, Eagle Ford Shale and Georgetown formations. As of June 30, 2014, we had 23 gross operated wells (16.7 net) producing in the Woodbine formation, consisting of 17 gross wells (12.8 net) in the Force area, three gross wells (1.8 net) in the Iola/Grimes area and three gross wells (2.1 net) in the Chalktown area.

South Texas (Buda)

During the quarter ended June 30, 2014, we brought three operated gross wells (1.7 net) on production that were spud during the first quarter of 2014, and an additional two gross wells (1.0 net) that were spud and completed during the second quarter. In total, eight wells were brought on production in the Buda formation for the six months ended June 30, 2014. We expect to continue having one to two rigs running full-time in 2014 as we continue to delineate the play over our 8,700 net acre position. As of June 30, 2014, we had twelve gross operated wells (6.2 net) producing from our Buda acreage.

Other (East Texas)

During the quarter ended June 30, 2014, we brought one gross (0.5 net) well on production that was spud during the first quarter of 2014, targeting the James Lime formation. In total, two wells were brought on production in the James Lime formation for the six months ended June 30, 2014. We will continue to monitor the production decline rate and liquids yield from our two wells in this region for several months, and if results support it, we could drill additional

James Lime wells later in the year or in 2015. We have approximately 4,800 net acres in the area prospective for the James Lime.

We also believe that the further exploitation of our acreage in the Haynesville and Mid-Bossier Shale dry gas formations will provide long-term natural gas reserve and production growth in the future; however, we do not anticipate devoting drilling capital to these formations until we see a sustained improvement in the natural gas price environment.

Other (Tuscaloosa Marine Shale)

We own a 25% non-operated working interest in the Crosby 12H-1 well in Wilkinson County, Mississippi, and an average non-operated working interest of 1.4% in four other wells in Mississippi, all targeting the TMS, an oil-focused shale play in central Louisiana and Mississippi. We own approximately 29,000 net acres in what is considered the TMS play.

Other (Colorado)

There has been increasing activity since 2011 in the vicinity of our Colorado acreage in pursuit of the Niobrara Shale oil formation. Recent industry activity in the area has proven that the application of horizontal drilling technology for oil in the shallower Niobrara Shale may provide attractive return possibilities; however, the prospect for full-scale economic development is still uncertain. We plan to monitor the 2014 industry activity and results of our peers in the Niobrara Shale to determine our strategy for maximizing the value of our position in the area.

New Frontiers and Resource Plays

We continue to make preparations to spud our first well under our previously announced Exploration Agreement with a private company targeting multiple formations in Fayette County, Texas. To date, we have purchased approximately 42,000 gross acres in this play (18,000 net to Contango). We believe that the current acreage position, if the play is successful, could add up to 200 gross drilling locations of resource potential to our drilling inventory, based on 150 acre spacing. The drilling of an initial well is expected to commence in mid-to-late third quarter.

We have the right to drill to earn approximately 119,500 gross acres (93,000 net acres with 80% working interest) in Wyoming on which we expect to soon test the application of horizontal drilling and hydraulic fractured completions on the Mowry Shale, a tight formation that has historically been produced thorugh vertical completions. We believe that our current acreage position, if the play is successful, could add up to 1,200 gross drilling locations of resource potential to our drilling inventory, based on 80 acre spacing. We expect to commence our initial operated well by the end of 2014.

Onshore Investments and Joint Ventures

Kaybob Duvernay - Alberta, Canada

In mid-2011, we began investing in Alta Resources Investments, LLC (“Alta”). On August 1, 2013, Alta sold its interest in the liquids-rich Kaybob Duvernay Play in Alberta, Canada, where we had invested approximately $15.2 million. We expect to receive approximately $30.5 million from the sales proceeds. Of this amount, $28.5 million has been received, and the remaining $2.0 million is expected to be received by the end of 2014.

Jonah Field - Sublette County, Wyoming

In April 2012, we, through our wholly-owned subsidiary, Contaro Company (“Contaro”), entered into a Limited Liability Company Agreement (as amended, the “LLC Agreement”) in connection with the formation of Exaro. Pursuant to the LLC Agreement, we have committed to invest up to $67.5 million in cash in Exaro, together with other parties for an aggregate commitment of approximately $183 million, resulting in a 37% ownership interest in Exaro. As of June 30, 2014, we had invested approximately $46.9 million in Exaro.

In April 2012, Exaro entered into an Earning and Development Agreement with Encana to provide funding of up to $380 million to continue the development drilling program in a defined area of Encana's Jonah Field located in Sublette County, Wyoming. This funding was to be comprised of the $182.5 million investment described above, debt and cash flow from operations. Upon investing the full amount of the $380 million, Exaro would have earned 32.5% of Encana's working interest in a defined joint venture area that comprises approximately 5,760 gross acres.

In May 2014, Encana, the operator of the field, completed the sale of its Jonah Field operations to an independent third-party. In connection with this sale, the Earning and Development Agreement with Encana was terminated, with Exaro having earned 1,040 acres in the defined joint venture area. For all future wells to be drilled in this area, Exaro will have between a 14.4% and 32.5% working interest, depending on the location of the well.

As of June 30, 2014, the Exaro venture had 113 new wells on production, producing at a rate of approximately 40 Mmcfed, net to Exaro, plus an additional 8 wells that are either in the completion or fracture stimulation phase. Exaro has indicated that they expect to have two drilling rigs running on this project during 2014. For the quarters ended June 30, 2014 and 2013, we recognized a gain of approximately $1.5 million and $1.9 million, net of tax expense of

$(0.8) million and $(1.0) million, respectively, as a result of our investment in Exaro. For the six months ended June 30, 2014 and 2013, we recognized a gain of approximately $3.1 million and $0.7 million, net of tax expense of $(1.7) million and $(0.4) million, respectively, as a result of our investment in Exaro. We do not anticipate making any additional equity contributions in 2014. See Note 8 to our Financial Statements - “Investment in Exaro Energy III LLC” for additional details related to this investment.

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

Results of Operations for the Three and Six Months Ended June 30, 2014 and 2013

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the three and six months ended June 30, 2014 and 2013. 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. Information for the three and six months ended June 30, 2013 includes results of operations of Contango prior to its merger with Crimson.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	%	2014	2013	%
Revenues:	(thousands except prices)			(thousands except prices)		
Oil and condensate sales	$ 38,340	$ 7,743	395.2 %	$ 73,440	$ 17,917	309.9 %
Natural gas sales	31,244	18,381	70.0 %	65,871	34,394	91.5 %
NGL sales	8,835	4,584	92.7 %	19,365	10,184	90.2 %
Total revenues	$ 78,419	$ 30,708	155.4 %	$ 158,676	$ 62,495	153.9 %
Production:						
Oil and condensate (thousand barrels)						
Offshore GOM	74	73	1.4 %	155	164	(5.5) %
Southeast Texas	192	—	n/a	378	—	n/a
South Texas	91	—	n/a	168	—	n/a
Other	24	—	n/a	37	—	n/a
Total oil and condensate	381	73	421.9 %	738	164	350.0 %
Natural gas (million cubic feet)						
Offshore GOM	4,893	4,428	10.5 %	10,263	8,795	16.7 %
Southeast Texas	888	—	n/a	1,702	—	n/a
South Texas	729	—	n/a	1,247	—	n/a
Other	220	—	n/a	349	—	n/a
Total natural gas	6,730	4,428	52.0 %	13,561	8,795	54.2 %
Natural gas liquids (thousand barrels)						
Offshore GOM	152	133	14.3 %	318	283	12.4 %
Southeast Texas	72	—	n/a	146	—	n/a
South Texas	31	—	n/a	56	—	n/a
Other	2	—	n/a	5	—	n/a
Total natural gas liquids	257	133	93.2 %	525	283	85.5 %
Total (million cubic feet equivalent)						
Offshore GOM	6,250	5,662	10.4 %	13,098	11,477	14.1 %

Southeast Texas	2,468	—	n/a		4,846	—	n/a	
South Texas	1,456	—	n/a		2,594	—	n/a	
Other	386	—	n/a		598	—	n/a	
Total production	10,560	5,662	86.5	%	21,136	11,477	84.2	%
Daily Production:								
Oil and condensate (thousand barrels per day)								
Offshore GOM	0.8	0.8	1.4	%	0.9	0.9	(5.5)	%
Southeast Texas	2.1	—	n/a		2.1	—	n/a	
South Texas	1.0	—	n/a		0.9	—	n/a	
Other	0.3	—	n/a		0.2	—	n/a	
Total oil and condensate	4.2	0.8	421.9	%	4.1	0.9	350.0	%
Natural gas (million cubic feet per day)								
Offshore GOM	53.8	48.7	10.5	%	56.7	48.6	16.7	%
Southeast Texas	9.8	—	n/a		9.4	—	n/a	
South Texas	8.0	—	n/a		6.9	—	n/a	
Other	2.4	—	n/a		1.9	—	n/a	
Total natural gas	74.0	48.7	52.0	%	74.9	48.6	54.2	%

Natural gas liquids (thousand barrels per day)						
Offshore GOM	1.7	1.5	14.3 %	1.8	1.6	12.4 %
Southeast Texas	0.8	—	n/a	0.8	—	n/a
South Texas	0.3	—	n/a	0.3	—	n/a
Other	—	—	n/a	—	—	n/a
Total natural gas liquids	2.8	1.5	93.2 %	2.9	1.6	85.5 %
Total (million cubic feet equivalent per day)						
Offshore GOM	68.7	62.2	10.4 %	72.4	63.4	14.1 %
Southeast Texas	27.1	—	n/a	26.8	—	n/a
South Texas	16.0	—	n/a	14.3	—	n/a
Other	4.2	—	n/a	3.3	—	n/a
Total production	116.0	62.2	86.5 %	116.8	63.4	84.2 %
Average Sales Price:						
Oil and condensate (per barrel)	$ 100.53	$ 106.07	(5.2) %	$ 99.52	$ 109.25	(8.9) %
Natural gas (per thousand cubic feet)	$ 4.64	$ 4.15	11.8 %	$ 4.86	$ 3.91	24.2 %
Natural gas liquids (per barrel)	$ 34.40	$ 34.47	(0.2) %	$ 36.91	$ 35.99	2.6 %
Total (per thousand cubic feet equivalent)	$ 7.43	$ 5.42	36.9 %	$ 7.51	$ 5.45	37.9 %
Expenses:						
Operating expenses	$ 11,576	$ 10,687	8.3 %	$ 22,629	$ 20,472	10.5 %
Exploration expenses	$ 10,853	$ 5	**	$ 37,784	$ 134	**
Depreciation, depletion and amortization	$ 39,901	$ 10,230	290.0 %	$ 74,303	$ 20,724	258.5 %
Impairment and abandonment of oil and gas properties	$ 1,371	$ 767	78.7 %	$ 16,566	$ 767	**
General and administrative expenses	$ 9,207	$ 5,757	59.9 %	$ 19,664	$ 8,965	119.3 %
Gain from investment in affiliates (net of taxes)	$ 1,478	$ 1,880	(21.4) %	$ 3,100	$ 733	322.9 %
Selected data per Mcfe:						
Operating expenses	$ 1.10	$ 1.89	(41.8) %	$ 1.07	$ 1.78	(39.9) %
General and administrative expenses	$ 0.87	$ 1.02	(14.7) %	$ 0.93	$ 0.78	19.2 %
Depreciation, depletion and amortization	$ 3.78	$ 1.81	108.8 %	$ 3.52	$ 1.81	94.5 %

** Greater than 1,000%

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Natural Gas, Oil and NGL Sales and Production

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

We reported revenues of approximately $78.4 million for the three months ended June 30, 2014, compared to revenues of approximately $30.7 million for the three months ended June 30, 2013. The increase in revenues was primarily attributable to: our merger with Crimson, which contributed approximately $41.3 million of revenues; approximately $2.9 million primarily due to a higher average realized price from our Dutch and Mary Rose field; approximately $2.3 million due to the increase in our working interest in Dutch wells in December 2013; and approximately $1.7 million more from production from our Vermilion 170 well.

Total equivalent production increased from 62.2 Mmcfed to 116.0 Mmcfed, an increase of which 88% is attributable to our merger with Crimson. Our net natural gas production for the three months ended June 30, 2014 was approximately 74.0 Mmcfd, compared to approximately 48.7 Mmcfd for the three months ended June 30, 2013. This increase primarily resulted from a 3.7 Mmcfd increase due to the December 2013 purchase of an additional interest in our Dutch wells, 2.5 Mmcfd higher production at Vermillion 170, which was shut-in for a portion of the 2013 quarter, and 20.2 Mmcfd contributed by Crimson. Net oil production increased from 797 barrels per day to 4,191 barrels per day, and NGL production increased from approximately 1,458 barrels per day to 2,823 barrels per day, almost all of which is attributable to our merger with Crimson.

Average Sales Prices

The average equivalent sales price realized for the three months ended June 30, 2014 was $7.43 compared to $5.42 for the three months ended June 30, 2013. This increase was attributable primarily to a higher percentage of oil and liquids to total production and to the increase in the price of natural gas to $4.64 per Mcf, compared to $4.15 per Mcf for the three months ended June 30, 2013, offset in part by an approximate $5.50 per barrel decrease in oil prices.

Operating Expenses

Operating expenses for the three months ended June 30, 2014 were approximately $11.6 million, or $1.10 per Mcfe, compared to $10.7 million, or $1.89 per Mcfe, for the three months ended June 30, 2013. Operating expenses for the three months ended June 30, 2014 included approximately $6.5 million of lease operating expenses, $3.1 million of production and ad valorem taxes, $1.6 million related to transportation and processing costs and $0.4 million of workover costs. For the three months ended June 30, 2013, operating expenses included approximately $3.1 million in lease operating expenses, $0.7 million of production taxes, $0.8 million in transportation and processing costs and $6.1 million in workover costs related primarily to our Vermilion 170 well.

The increase in lease operating expenses from $3.1 million to $6.5 million is primarily related to our merger with Crimson, which incurred approximately $4.7 million of lease operating expenses for the three months ended June 30, 2014, and the incremental cost related to several additional wells brought to production.

Exploration Expenses

Exploration expenses for the three months ended June 30, 2014 included $10.1 million in dry-hole costs related to our Ship Shoal 255 well finalized early in the second quarter.

Impairment Expenses

Impairment expenses for the three months ended June 30, 2014 included a $0.5 million impairment of an existing platform that was expected to be used by the Ship Shoal 255 well.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended June 30, 2014 was approximately $39.9 million or $3.78 per Mcfe. This compares to approximately $10.2 million or $1.81 per Mcfe for the three months ended June 30, 2013. The increase in depreciation, depletion and amortization was primarily attributable to increased production as a result of our merger with Crimson which contributed $29.0 million to the depreciation, depletion and amortization for the three months ended June 30, 2014. The higher depletion rate reflects the addition of the Crimson properties as a result of the Merger.

General and Administrative Expenses

General and administrative expenses for the three months ended June 30, 2014 were approximately $9.2 million, compared to $5.8 million for the three months ended June 30, 2013. This increase was primarily due to a $2.4 million increase in salaries and benefits as a result of the Merger ($1.3 million of which was an accrued merger-related bonus paid to Mr. Romano in July 2014) and $1.0 million in non-cash stock-based compensation.

Gain from Affiliates

For the three months ended June 30, 2014, the Company recorded a gain from affiliates of approximately $1.5 million, net of tax expense of $(0.8) million, related to our investment in Exaro, compared to a gain of $1.9 million, net of tax expense of $(1.0) million, for the three months ended June 30, 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Natural Gas, Oil and NGL Sales and Production

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

We reported revenues of approximately $158.7 million for the six months ended June 30, 2014, compared to revenues of approximately $62.5 million for the six months ended June 30, 2013. The increase in revenues was primarily attributable to: our merger with Crimson, which contributed approximately $78.4 million of revenues; approximately $9.1 million primarily due to a higher average realized price from our Dutch and Mary Rose field; approximately $4.6 million due to the acquisition of an additional working interest in December 2013; approximately $5.4 million more from production from our Vermilion 170 well, which was shut-in for a substantial portion of the first quarter of 2013; and a higher average equivalent sales price realized for the period.

Total equivalent production increased from 63.4 Mmcfed to 116.8 Mmcfed, an increase of which 83% is attributable to our merger with Crimson. Our net natural gas production for the six months ended June 30, 2014 was approximately 74.9 Mmcfd, compared to approximately 48.6 Mmcfd for the six months ended June 30, 2013. This increase was primarily associated with a 3.6 Mmcfd increase due to the increase in ownership in the Dutch wells, a 3.3 Mmcfd increase due to reinstatement of production at Vermillion 170 and 18.2 Mmcfd was contributed by Crimson. Net oil production increased from 903 barrels per day to 4,077 barrels per day, and NGL production increased from approximately 1,563 barrels per day to 2,899 barrels per day, almost all of which was attributable to our merger with Crimson.

Average Sales Prices

The average equivalent sales price realized for the six months ended June 30, 2014 was $7.51 compared to $5.45 for the six months ended June 30, 2013. This increase resulted primarily from the higher percentage of oil and liquids production to total production and to the increase in the price of natural gas to $4.86 per Mcf, compared to $3.91 per Mcf for the six months ended June 30, 2013. Additionally, NGL prices increased to $36.91 per barrel, compared to $35.99 per barrel for the six months ended June 30, 2013. The price for oil decreased from $109.25 per barrel for the six months ended June 30, 2013 to $99.52 per barrel for the six months ended June 30, 2014.

Operating Expenses

Operating expenses for the six months ended June 30, 2014 were approximately $22.6 million, or $1.07 per Mcfe, compared to $20.5 million, or $1.78 per Mcfe, for the six months ended June 30, 2013. Operating expenses for the six months ended June 30, 2014 included approximately $12.9 million of lease operating expenses, $6.1 million of production and ad valorem taxes, $2.7 million related to transportation and processing costs and $0.9 million of workover costs. For the six months ending June 30, 2013, operating expenses included approximately $5.6 million in lease operating expenses, $1.7 million of production taxes, $1.8 million in transportation and processing costs and $11.4 million in workover costs related primarily to our Vermilion 170 well.

The increase in lease operating expenses from $5.6 million to $12.9 million was primarily related to our merger with Crimson, which incurred approximately $8.8 million of lease operating expenses for the six months ended June 30, 2014, and to the incremental cost related to several additional wells being brought to production.

Exploration Expenses

Exploration expenses for the six months ended June 30, 2014 included $36.8 million in dry-hole costs related to our Ship Shoal 255 well.

Impairment Expenses

Impairment expenses for the six months ended June 30, 2014 included a $3.5 million impairment of leasehold cost related to the Ship Shoal 255 block and $12.1 million for impairment of an existing platform, that was expected to be used by the Ship Shoal 255 well if it had been successful.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the six months ended June 30, 2014 was approximately $74.3 million or $3.52 per Mcfe compared to approximately $20.7 million or $1.81 per Mcfe for the six months ended June 30, 2013. The increase in depreciation, depletion and amortization was primarily attributable our merger with Crimson which contributed $51.7 million to this expense for the six months ended June 30, 2014. The higher depletion rate reflects the addition of the Crimson properties as a result of the Merger.

General and Administrative Expenses

General and administrative expenses for the six months ended June 30, 2014 were approximately $19.7 million, compared to $9.0 million for the six months ended June 30, 2013. This increase was primarily due to a $6.5 million increase in salaries and benefits as a result of the Merger ($2.6 million of which was an accrued merger-related bonus paid to Mr. Romano in July 2014) and $2.1 million in non-cash stock-based compensation. Other changes to general and administrative expenses include a $1.3 million increase in office and other related costs.

Gain from Affiliates

For the six months ended June 30, 2014, the Company recorded a gain from affiliates of approximately $3.1 million, net of tax expense of $(1.7) million, related to our investment in Exaro, compared to a gain of $0.7 million, net of tax expense of $(0.4) million, for the six months ended June 30, 2013.

Capital Resources and Liquidity

During the three months ended June 30, 2014, we incurred $56.2 million for capital projects. This includes $23.5 million related to drilling of the Woodbine formation in our Madison and Grimes counties area, $11.4 million for drilling of our Ship Shoal 255 well, $10.0 million in drilling the Buda formation in South Texas and $9.4 million for leased acreage in new areas.

During the six months ended June 30, 2014, we incurred $117.2 million for capital projects. This includes $38.2 million related to drilling of the Woodbine formation in our Madison and Grimes counties area, $33.3 million for drilling of our Ship Shoal 255 well, $19.1 million in drilling the Buda formation in South Texas, $8.9 million in East Texas, $11.0 million for leases in new areas and $3.3 million for facilities at our South Timbalier 17 well.

Our capital expenditure budget for 2014 is currently forecasted to be between $215 and $225 million, including the amounts spent during the six months ended June 30, 2014, and is expected to be funded primarily from internally generated cash flow.

Additionally, the Company often reviews acquisitions and prospects presented to us by third parties, and we may decide to invest in one or more of these opportunities. There can be no assurance that we will invest or that any investment we enter into will be successful. These potential investments are not part of our current capital budget and would require us to invest additional capital. Natural gas and oil prices continue to be volatile and our resources may be insufficient to fund any of these opportunities.

Cash From Operating Activities

Cash flows from operating activities provided approximately $127.8 million in cash for the six months ended June 30, 2014 compared to $48.7 million for the same period in 2013. For the six months ended June 30, 2014 and 2013, cash flows from operating activities, exclusive of changes in working capital accounts, were $112.0 million and $35.6 million, respectively.

Cash From Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2014 were approximately $103.9 million, including approximately $109.3 million used for capital expenditures related to drilling and developing wells, offset by $5.4 million in Alta distributions received during the period. Cash used in investing activities for the six months ended June 30, 2013 were approximately $26.7 million, including an $11.8 million outflow for capital expenditures related to drilling and developing wells and additional equity investments of $1.8 million in Alta and $13.1 million in Exaro.

Cash From Financing Activities

Cash flows used in financing activities for the six months ended June 30, 2014 were approximately $23.9 million, primarily all related to partial repayment of short-term borrowings outstanding under our RBC Credit Facility. The Company did not have any cash flows from financing activities for the six months ended June 30, 2013.

RBC Credit Facility

In October 2013, the Company entered into a $500 million four-year revolving credit facility with Royal Bank of Canada and other lenders (the "RBC Credit Facility") with an initial hydrocarbon supported borrowing base of $275 million, which was reaffirmed as of May 1, 2014. This facility replaced the Company's $40 million secured revolving Credit Agreement with Amegy Bank ("Amegy Credit Agreement"). The Company incurred $2.2 million of arrangement and upfront fees for the RBC Credit Facility. Proceeds of the RBC Credit Facility will also be used (i) to finance working capital and for general corporate purposes (including requisitions), (ii) for permitted acquisitions and (iii) to finance transaction expenses in connection with the RBC Credit Facility and the Merger. The RBC Credit Facility is collateralized by substantially all of the assets of the Company and its subsidiaries. Borrowings under the RBC Credit Facility bear interest at a rate that is dependent upon LIBOR or the U.S. prime rate of interest, plus a margin dependent upon the amount outstanding under the facility.

As of August 7, 2014, the Company had outstanding debt of approximately $77.4 million under the RBC Credit Facility, and had no cash on hand.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States.

The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in Note 2 of Notes to Consolidated Financial Statements included in our Form 10-K/A for the year ended December 31, 2013. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company's consolidated financial statements:

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.

Reserve Estimates

While we are reasonably certain of recovering our reported reserves, the Company's estimates of natural gas and oil reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable natural gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future natural gas and oil prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future development costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected natural gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's natural gas and oil properties and/or the rate of depletion of such natural gas and oil properties.

Impairment of Natural Gas and Oil Properties

The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company compares expected undiscounted future net cash flows from each field to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company’s estimate of future natural gas and oil prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Drilling activities in an area by other companies may also effectively condemn leasehold positions. Given the complexities associated with natural gas and oil reserve estimates and the history of price volatility in the natural gas and oil markets, events may arise that will require the Company to record an impairment of its natural gas and oil properties, and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

Derivative Instruments

At the end of each reporting period, we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives is reported in Other Income and Expense as Loss on derivatives, net.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Accounting for uncertainty in income taxes prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities.

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income and changes in shareholder ownership that limit the use of net operating losses under the Internal Revenue Code Section 382.

Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns.

We have a significant deferred tax asset associated with the net tax operating losses acquired in the Merger. The amount of the deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced. We expect we will be able to utilize all deferred tax assets despite the limitations of Internal Revenue Code Section 382, except those for which valuation allowance was provided. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. Any adjustments or changes in our estimates of asset recovery could have an impact on our results of operations. See Note 10 - "Income Taxes" to our consolidated financial statements.

The effective tax rate for the three and six months ended June 30, 2014 varies from the statutory rate primarily due to the effect of state income taxes, offset by the permanent differences related to deductible Merger transaction costs and additional depletion deductions for state taxes resulteing from the return to provision adjustments for federal and state taxes. The effective tax rate for the three and six months ended June 30, 2013 varied from the statutory rate due to non-taxable income related to life insurance proceeds partially offset by state income taxes and non-deductible merger related expenses.

Business Combinations

Accounting for business combinations requires that the various assets acquired and liabilities assumed in a business combination be recorded at their respective acquisition date fair values. The most significant estimates to us typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. Deferred taxes are recorded for any differences between fair value and tax basis of assets acquired and liabilities assumed. To the extent the purchase price plus the liabilities assumed (including deferred income taxes recorded in connection with the transaction) exceeds the fair value of the net assets acquired, we are required to record the excess as goodwill. As the fair value of assets acquired and liabilities assumed is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value assigned to recoverable oil and gas reserves is subject to the impairment test when facts or circumstances indicate that the value of the properties may be impaired, and the value assigned to unproved properties is assessed at least annually to ascertain whether impairment has occurred. Our consolidated balance sheet presented as of June 30, 2014 reflects the purchase price allocations based on available information. If the initial accounting for the business combination is not complete, the amounts recognized for assets acquired and liabilities assumed in the financial statements may be adjusted during the measurement period of up to one year as specified by ASC 805, Business Combinations.

Recent Accounting Pronouncements

In May 2014, the FASB and the International Accounting Standards Board (“IASB”) jointly issued new accounting guidance for recognition of revenue. This new guidance replaces virtually all existing US GAAP and IFRS guidance on revenue recognition. The new guidance is effective for fiscal years beginning after December 15, 2016. This new guidance applies to all periods presented. Therefore, when the Company issues its financial statements on Forms 10-Q and 10-K for periods included in its year ended December 31, 2017, its comparative periods that are presented from the years ended December 31, 2015 and 2016, must be retrospectively presented in compliance with this new guidance. Early adoption is not allowed for US GAAP. The new guidance requires companies to make more estimates and use more judgment than under current accounting guidance. The Company is currently evaluating (i) the two allowed adoption methods to determine which method it plans to use for retrospective presentation of comparative periods and (ii) whether the implementation of this new guidance will have a material impact on the Company's consolidated financial position or results of operations for the periods presented.

In April 2014, the FASB issued amendments to guidance for reporting discontinued operations and disposals of components of an entity. The amended guidance requires that a disposal representing a strategic shift that has (or will have) a major effect on an entity's financial results or a business activity classified as held for sale should be reported as discontinued operations. The amendments also expand the disclosure requirements for discontinued operations and add new disclosures for individually significant dispositions that do not qualify as discontinued operations. The amendments are effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2014 (early adoption is permitted only for disposals that have not been previously reported). The implementation of the amended guidance is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. We are currently evaluating the provisions of ASU 2014-08 and assessing the impact, if any, it may have on our financial position and results of operations.

In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), revised its criteria related to internal controls over financial reporting from the originally established 1992 Internal Control - Integrated Framework with 2013 Internal Control - Integrated Framework. The modified framework provides enhanced guidance that ties control objectives to the related risk, enhancement of governance concepts, increased emphasis on globalization of markets and operations, increased recognition of use and reliance on information technology, increased discussion of fraud as it relates to internal control, changes of control deficiency descriptions, and that internal reporting is included in both financial and nonfinancial objectives. The revised framework is effective for interim and annual periods beginning after December 15, 2013. We plan to implement any changes required by the new COSO framework during the year ended December 31, 2014. Currently, we are evaluating the provisions of the revised framework and continue to assess the impact, if any, it may have on our internal control structure.

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2013-04 Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (ASU 2013-04). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. U.S. GAAP does not include specific guidance on accounting for such obligations with joint and several liability, which has resulted in diversity in practice. The accounting update is effective for interim and annual periods beginning after December 15, 2013. The provisions of this accounting update did not have a material impact on our financial position or results of operations.

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of June 30, 2014, the primary off-balance sheet arrangements that we have entered into included short-term drilling rig contracts and operating lease agreements, all of 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 Annual Report on Form 10-K/A for the year ended December 31, 2013, we have no other off-balance sheet arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk

We are exposed to various risks including energy commodity price risk for our natural gas and oil production. When oil, natural gas and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. Our major commodity price risk exposure is to the prices received. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for natural gas and oil are volatile and unpredictable. For the quarter ended June 30, 2014, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $8.0 million impact on our revenues.

Derivative Instruments and Hedging Activity

We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management strategy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our cash flows. The types of derivative instruments that we typically utilize include swaps and costless collars. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 40% to 50% of our current and anticipated production. Our hedge strategy and objectives may change significantly as our operational profile changes and/or commodities prices change.

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

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Currently, we do not have any derivative contracts to reduce the exposure to market rate fluctuations. At June 30, 2013, 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 - "Derivative Instruments" for more details. As of June 30, 2014 we have 2.1 Bcfe equivalent production hedged between July 1, 2014 and December 31, 2014. For the remainder of 2014 production, we have 81 MBbl of crude oil hedges at an average Brent floor price of $104.01/Bbl, 72 MBbl of crude oil hedges at an average WTI floor price of $91.67/Bbl and 1.2 Bcf of natural gas hedges at an average floor price of $3.84/MMBtu.

Interest Rate Sensitivity

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

As of June 30, 2014, our total long-term debt was $66.0 million, which bears interest at a floating or market interest rate that is tied to the prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the quarter ended June 30, 2014, our effective rates fluctuated between 1.9 percent and 4.3 percent, depending on the term of the specific debt drawdowns. At June 30, 2014, we did not have any outstanding interest rate swap agreements. As of June 30, 2014, the weighted average interest rate on our variable rate debt was 2.0% 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 $0.2 million for the three month period and $0.3 million for the six month period.

Other Financial Instruments

As of June 30, 2014, we had no cash or cash equivalents based on our cash management policy. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of June 30, 2014, an immediate 10% change in interest rates is not expected to have a material effect on our near-term financial condition or results of operations.

Item 4. Controls and Procedures

Allan D. Keel, our Chairman, President and Chief Executive Officer, together with our Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the Company's "disclosure controls and procedures" as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as of June 30, 2014. Based upon that evaluation, the Company's management concluded that, as of June 30, 2014, the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to ensure that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our President and Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company's internal control over financial reporting that occurred during the six months ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

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

Mineral interest owners in South Louisiana filed suit against a subsidiary of the Company and several co-defendants in June 2009 in the 31st Judicial District Court situated in Jefferson Davis Parish, Louisiana alleging failure to act as a reasonably prudent operator, failure to explore, waste, breach of contract, etc. in connection with two wells located in Jefferson Davis Parish. Many of the alleged improprieties occurred prior to our ownership of an interest in the wells at issue, although we may have assumed liability otherwise attributable to our predecessors-in-interest through the acquisition documents relating to the acquisition of our interest in these wells. The damages most recently alleged by the plaintiffs are approximately $13.4 million. We and our co-defendants are vigorously defending this lawsuit and believe that we have meritorious defenses. We and our co-defendants obtained a favorable judgment from the trial court following a trial, but the judgment is being appealed by the plaintiffs. A companion case involving the same claims, wells, etc. was filed in the same court on April 19, 2013 on behalf of additional mineral interest owners.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by us or by predecessor operators to which we have granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. The trial court has granted plaintiff's motion for partial summary judgment as to liability (but not damages). While preserving our right to appeal as to liability, we recently entered into a partial judgment with the plaintiff which establishes the amount of damages recoverable by the plaintiff, if it ultimately prevails in this case, at approximately $5.3 million (which excludes pre-judgment interest although the plaintiff may appeal the trial court's ruling that interest is not owed). We are vigorously defending this lawsuit, believe that we have meritorious defenses and intend to appeal the aforementioned decision.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson “A” Unit in Liberty County in Texas. This case was subsequently transferred to district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). We have made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. In their initial pleading the plaintiff alleges damages in excess of $6.0 million, which is generally in line with amounts received on its undisputed 1/16th mineral interest as of the date the suit was filed. As of July 31, 2014, the Plaintiff had received approximately $9.3 million in royalties in respect of its undisputed interest. We are vigorously defending this lawsuit and believe that we have meritorious defenses. We believe if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights we may have against other working interest and/or royalty interest owners in the unit.

In connection with our Merger, several class action lawsuits have been brought by Crimson stockholders in Delaware Chancery Court seeking damages and injunctive relief including, among other things, compensatory damages and costs and disbursements relating to the lawsuits. Various combinations of the Company, certain subsidiaries of the Company, members of Crimson’s pre-merger board of directors, members of Crimson’s pre-merger management team and Oaktree Capital Management

L.P. have been named as defendants in these lawsuits. The Delaware lawsuits have been consolidated into a single action referred to as In Re: Crimson Exploration Inc. Stockholder Litigation; C.A. 8541-VCP. Additionally, on July 13, 2013, a separate and similar complaint was filed in the District Court of Harris County Texas, in the matter of Fisichella Family Trust v. Crimson Exploration Inc. It is possible that additional similar lawsuits may be filed.

The merger-related lawsuits allege, among other things, that Crimson's board of directors failed to take steps to obtain a fair price, failed to properly value Crimson, failed to protect against alleged conflicts of interest, failed to conduct a reasonably informed evaluation of whether the transaction was in the best interests of stockholders, failed to fully disclose all material information to stockholders, acted in bad faith and for improper motives, engaged in self-dealing, discouraged other strategic alternatives, took steps to avoid competitive bidding, and agreed to allegedly unreasonable deal protection mechanisms, including the no-shop, fiduciary-out provisions and termination fee. The lawsuits also allege that Contango and certain other defendants aided and abetted the other defendants in violating duties to the Crimson stockholders. The known plaintiffs in these lawsuits collectively owned a very small percentage of the total outstanding shares of Crimson common stock at the time of the Merger, which was approved by Contango's pre-merger shareholders (89% of outstanding shares and 99% of voted shares were voted in favor of the Merger) and Crimson's pre-merger shareholders (69% of outstanding shares and 88% of voted shares were voted in favor of the Merger). The Company believes that these merger-related lawsuits are without merit and is contesting them vigorously.

In February 2011, a subsidiary of the Company and certain of our working interest partners and insurance carriers brought suit against a marine construction, dredging and tunneling company and an instrumentality of the United States of America in the U.S. District Court for the Southern District of Texas - Houston Division seeking monetary damages for damage to an offshore pipeline which was struck by a dredge. Following a bench trial in December 2013, we and our co-defendants obtained a favorable judgment from the trial court, but the judgment is being appealed by the defendants.

While many of these matters involve inherent uncertainty and we are unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, we believe that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. The Company has maintained an officers and directors liability insurance policy for Crimson former directors and officers and has made a claim under the policy for coverage of these merger related lawsuits.

Item 1A. Risk Factors

For discussion regarding our risk factors, see Item 1 of Part 1 of our Annual Report on Form 10-K/A for the year ended December 31, 2013 and our Transition Report on Form 10-K for the transition period ended December 31, 2013. Those risk and uncertainties are not the only ones facing us, and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition, and/or results of operations

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

(c) Issuer Purchases of Equity Securities

None.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

(a) Exhibits:

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized.

CONTANGO OIL & GAS COMPANY

Date: August 11, 2014 By: /S/ ALLAN D. KEEL
Allan D. Keel

President and Chief Executive Officer

(Principal Executive Officer)

Date: August 11, 2014 By: /S/ E. JOSEPH GRADY
E. Joseph Grady

Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

Date: August 11, 2014 By: /S/ YAROSLAVA MAKALSKAYA
Yaroslava Makalskaya

Vice President, Chief Accounting Officer and Controller

(Principal Accounting Officer)

Exhibit Number		Description
2.1	*	Agreement and Plan of Merger, dated as of April 29, 2013, by and among Contango Oil & Gas Company, Contango Acquisition, Inc. and Crimson Exploration Inc. (3)
3.1		Certificate of Incorporation of Contango Oil & Gas Company. (1)
3.2		Second Amended and Restated Bylaws of Contango Oil & Gas Company. (5)
3.4		Amendment to the Certificate of Incorporation of Contango Oil & Gas Company. (2)
10.1		Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and The Lenders Signatory Hereto dated October 1, 2013. (4)
10.2		First Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto. (6)
10.3		Termination Agreement between Juneau Exploration, L.P., and Contaro Company, dated July 15, 2014. ††
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.

†† Furnished herewith.

* Schedules to the agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The

Company undertakes to furnish supplementally copies of any of the omitted schedules upon request by the SEC.

.

1. Filed as an exhibit to the Company’s Current Report on Form 8-K, dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000.

2. Filed as an exhibit to the Company’s Quarterly Report on Form 10-QSB for the quarter ended December 31, 2002, dated November 14, 2002, as filed with the Securities and Exchange Commission.

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

4. Filed as an exhibit to the Company’s Current Report on Form 8-K dated as of October 1, 2013, as filed with the Securities and Exchange Commission on October 2, 2013.

5. Filed as an exhibit to the Company’s Current Report on Form 8-K dated as of March 19, 2014, as filed with the Securities and Exchange Commission on March 21, 2014.

6. Filed as an exhibit to the Company’s Current Report on Form 8-K dated as of April 11, 2014, as filed with the Securities and Exchange Commission on April 15, 2014.