CONTANGO OIL & GAS CO
Form 10-K/A
March 28, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K/A
(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from July 1, 2013 to December 31, 2013

Commission file number 001-16317

CONTANGO OIL & GAS COMPANY
(Exact name of registrant as specified in its charter)

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

717 Texas Avenue, Suite 2900
Houston, Texas 77002
(Address of principal executive offices)
(713) 236-7400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, Par Value $0.04 per share	NYSE MKT

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [X]

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 [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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 [X] Non-accelerated filer [ ] Smaller reporting company [ ]
(Do not check if 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 [X]

At June 30, 2013, the aggregate market value of the registrant's common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE MKT, was $455 million. As of March 27, 2014, there were 19,367,411 shares of the registrant's common stock outstanding.

Documents Incorporated by Reference

Items 10, 11, 12, 13 and 14 of Part III have been omitted from this report since the registrant will file with the Securities and Exchange Commission, not later than 120 days after the close of its fiscal year, a definitive proxy statement, pursuant to Regulation 14A. The information required by Items 10, 11, 12, 13 and 14 of this report, which will appear in the definitive proxy statement, is incorporated by reference into this Form 10-K/A.

Explanatory Note

On October 1, 2013, Contango Oil & Gas Company ("Contango", "we" or the "Company") completed a merger with Crimson Exploration Inc. ("Crimson") under an all-stock transaction pursuant to which Crimson became a wholly-owned subsidiary of the Company (the "Merger"). The Merger is described in greater detail within this Annual Report on Form 10-K/A.

In connection with the closing of the Merger, our Board of Directors approved a change of our fiscal year end from June 30 to December 31, commencing with the twelve-month period beginning on January 1, 2014. As a result of this change, on March 3, 2014 we filed a Transition Report on Form 10-K for the six-month period ended December 31, 2013 (the "Original Filing"). This Annual Report on Form 10-K/A is filed to present a recast of historical financial information for the three-year period ended December 31, 2013. Financial statements as of December 31, 2013 and 2012 and for the three years ended December 31, 2013 include consolidated results of operations of both Contango and Crimson for the period from the closing of the Merger on October 1, 2013 to December 31, 2013 and consolidated financial statements of Contango only for all other periods.

This Annual Report on Form 10-K/A should be read in conjunction with the Original Filing. This Annual Report on Form 10-K/A does not generally reflect events that occurred after the filing date of the Original Filing although certain provisions have been updated or otherwise modified where we believe appropriate to give proper context to the results for the periods included herein. In addition, the following provisions of the Original Filing have also been amended:

- Cover page. We have updated the shares of common stock outstanding as of March 27, 2014.
- Part II. Item 5. General. We have updated the shares of common stock outstanding and issued as of March 27, 2014.
- Part II. Item 7. Capital Resources and Liquidity. We have updated the amount of debt outstanding as of March 27, 2014.
- Part IV. Item 15(b). Exhibits. We have amended the exhibits to reference the current version of the Company's Bylaws.
- We have updated the Annual Report to reference the resignation of Mr. Brad Juneau from the board of directors.

Other than as described in this explanatory note, this Annual Report on Form 10-K/A does not modify or update the disclosures in the Original Filing.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K/A FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013
TABLE OF CONTENTS

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 this report 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. On October 1, 2013 the Company's board of directors approved a change in fiscal year end from June 30 to December 31.

All references in this Form 10-K/A to the “Company”, “Contango”, “we”, “us” or “our” are to Contango Oil & Gas Company and wholly-owned subsidiaries. Unless otherwise noted, all information in this Form 10-K/A relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

PART I

Item 1. Business

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 and in the onshore Gulf Coast region of the United States and Colorado.

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 Exploration Inc. activity (October - December). This Form 10-K/A presents our information for the twelve months ended December 31, 2013, 2012 and 2011. Unless otherwise noted, all references to "years" in this report refer to the twelve-month periods ended December 31 of each year.

On October 1, 2013, we completed a merger with Crimson Exploration Inc. (“Crimson”), in an all-stock transaction pursuant to which Crimson became a wholly-owned subsidiary of Contango (the “Merger"). As a result of the Merger, each share of Crimson common stock was converted into the right to receive 0.08288 shares of common stock of the Company. 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 the 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.

Following the Merger, the newly constituted board of directors of the Company consisted of Joseph J. Romano, Allan D. Keel, B.A. Berilgen, B. James Ford, Brad Juneau, Ellis L. McCain, Charles M. Reimer, and Steven L. Schoonover. The board of directors appointed Allan D. Keel as President and Chief Executive Officer and E. Joseph Grady as Senior Vice President and Chief Financial Officer of the Company. Joseph J. Romano has continued as Chairman of the Board. Messrs. Keel, Grady and certain other employees of Crimson entered into employment agreements with the Company that became effective upon the consummation of the Merger. The combined company has its headquarters and principal corporate office in Houston, Texas.

We have historically focused our operations in the Gulf of Mexico (“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 provide long-term growth potential from multiple formations.

Our production for the year ended December 31, 2013 was approximately 87% offshore and 13% onshore, and 73% natural gas and 27% oil and natural gas liquids. Our production for the three months ended December 31, 2013 was approximately 63% offshore and 37% onshore, and 66% natural gas and 34% oil and natural gas liquids. As of December 31, 2013, our proved reserves were approximately 61% offshore and 39% onshore, and 66% natural gas and 34% oil and natural gas liquids.

Additionally, we have (i) a 37% equity investment in Exaro Energy III LLC (“Exaro”), which participates in a joint venture with Encana Oil & Gas (USA) Inc. (“Encana”) that is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; (ii) an approximate 29,000 net acre position, 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 we believe are prospective in the Niobrara Shale oil play, and (v) seven exploratory prospects in the shallow waters of the Gulf of Mexico.

We intend to grow reserves and production by developing our existing producing property base, by exploiting our oil/liquids resource potential, and by pursuing opportunistic acquisitions in areas where we have current operations and specific operating expertise, as well as new areas we identify that we feel have significant exploration and operational upside. 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. Until we see improvement in natural gas prices, we will concentrate our drilling activity predominantly on further developing our oil and liquids-rich onshore assets in Southeast Texas and South Texas, complemented by offshore exploratory drilling. In 2014 specifically, we will focus on our inventory of crude oil and liquids-rich projects with rig programs targeting the Woodbine in Madison and Grimes Counties, Texas, the Buda in Dimmit County, Texas and the James Lime in San Augustine County, Texas. We also currently plan to drill a number of other wells testing new formations in existing areas and one to two exploratory wells in the shallow waters of the Gulf of Mexico.

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.

As of December 31, 2013, our proved reserves, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") and William M. Cobb and Associates ("Cobb"), our independent petroleum engineering firms, in accordance with reserve reporting guidelines required by the Securities and Exchange Commission ("SEC"), were approximately 313.9 Bcfe, consisting of 207.9 Bcf of natural gas and 17.7 MMBbl of crude oil, condensate and natural gas liquids, with a PV 10 of $987.2 million, and a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $771.4 million. As of December 31, 2013, 66% of our proved reserves were natural gas, 81% were proved developed and 96.6% were attributed to wells and properties operated by us. PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure to PV 10 is provided under Item 2. Properties PV-10.

The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2013, excluding our reserves attributable to our investment in Exaro, as estimated by NSAI and Cobb and our net average daily production for the year ended December 31, 2013:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (2) (Mmcfe/d)
Offshore GOM	190.5	6 %	79 %	15 %	99 %	67.1
Southeast Texas	52.3	53 %	32 %	15 %	58 %	24.3
South Texas	63.3	25 %	58 %	17 %	51 %	14.7
Other (1)	7.8	28 %	59 %	13 %	63 %	1.7
Total	313.9					107.8

(1) East Texas, Mississippi, Louisiana, TMS and Colorado
(2) Offshore GOM daily production is averaged over 365 days. Southeast Texas, South Texas and Other daily production is averaged over 92 days (the post-Merger period).

Our Strategy

Key elements of our business strategy are:

- Enhance our portfolio by dedicating the majority of our drilling capital to our oil and liquids-rich opportunities. Due to the superior economics from oil production, we will allocate most of our 2014 onshore capital budget to oil and liquids-weighted opportunities as we transition from a natural gas weighted production profile to a more balanced reserve and production profile between oil/liquids and natural gas. We currently plan to develop the oil and natural gas liquids resource potential that we believe exists, from numerous formations, on our Madison and Grimes County acreage in Southeast Texas, our Zavala and Dimmit County acreage in South Texas and our San Augustine County acreage in East Texas. If warranted by market conditions, success in these areas and capital availability, we may further accelerate our drilling program in one or more areas. Until the outlook for natural gas prices for a sustained period of time improves significantly, we do not plan to further develop our acreage position in the Haynesville/Mid-Bossier natural gas play in East Texas. For the year ended December 31, 2013, our production profile was approximately 73% natural gas and 27% oil and natural gas liquids, on an equivalent Mcfe basis. For the three months ended December 31, 2013, our production profile was approximately 66% natural gas and 34% oil and natural gas liquids.
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Complement the exploitation of our lower-risk onshore resource plays with potentially high-impact offshore exploration. We have historically depended upon Juneau Exploration, L.P. (“JEX”) for offshore prospect generation expertise and to review prospects submitted by third parties. JEX is a private company formed for the purpose of generating offshore and onshore domestic natural gas and oil prospects and is experienced and has a successful track record in exploration. We currently have seven offshore prospects and intend to continue to review and consider offshore exploration opportunities generated by JEX to increase our reserves base. Until his resignation on March 19, 2014, Mr. Brad Juneau, the sole manager of the general partner of JEX, was a member of the Company’s board of directors.

- Pursue accretive, opportunistic acquisitions that meet our strategic and financial objectives. We intend to continue evaluating opportunistic acquisitions of crude oil and natural gas properties, including both undeveloped and developed reserves, in areas where we currently have a presence and/or specific operating expertise, as well as new areas that we feel have significant exploration, exploitation or operational upside.
- Reduce near-term commodity price exposure through hedging. We utilize commodity derivative instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We currently use a series of swaps and costless collars to accomplish our commodity price hedging strategy. As of December 31, 2013, we have 9.5 Bcfe of equivalent production hedged between January 1, 2014 and December 31, 2014. For 2014 production we have 0.2 MMBbl of crude oil hedges at an average Brent floor price of $104.29/Bbl, 0.3 MMBbl of crude oil hedges at an average WTI floor price of $95.05/Bbl and 6.9 Bcf of natural gas hedges at an average floor price of $3.94 /MMBtu.
- Selectively exploit our existing onshore producing conventional property base to generate additional cash flows. We believe our multi-year drilling inventory of exploitation opportunities on our existing onshore conventional producing properties provides us with a solid, dependable platform for future reserve and production growth. We own 3D seismic data that covers substantially all of our Liberty County acreage in Southeast Texas, giving us a higher degree of confidence in the potential in this area. However, as a result of our desire to more extensively develop our resource plays, we do not expect to allocate significant drilling capital to further develop these assets in 2014.

Offshore Gulf of Mexico

As of December 31, 2013, the Company's offshore production consisted of seven federal and five State of Louisiana Company-operated wells in the shallow waters of the Gulf of Mexico. These 12 wells produce from three fields. The following summary table sets forth certain information with respect to our offshore reserves as of and for the year ended December 31, 2013:

Field	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Dutch and Mary Rose	170.4	7 %	79 %	14 %	99 %	59.4
Vermilion 170	17.7	5 %	77 %	18 %	100 %	6.7
Other Offshore	2.4	9 %	91 %	— %	8 %	1.0
Total	190.5					67.1

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 own 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 production and normal decline, we anticipate placing our Dutch and Mary Rose wells on central compression at the Eugene Island 11 platform in 2014. We have designed a turbine type compressor for the platform which will be of sufficient capacity to service all ten of our Dutch and Mary Rose wells. As of December 31, 2013, we had incurred approximately $8.8 million to design and build the compressor, and have budgeted an additional $0.8

million for the installation anticipated in June 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 $18.8 million, subject to a purchase price adjustment based on production and operating expenses between the effective date of July 1, 2013 and the closing date of December 12, 2013. Preliminary estimated adjustments of approximately $3.8 million reduce the purchase price to a total of $15 million, net to the Company. The purchase price is expected to be finalized in the first quarter of 2014.

Vermilion 170 Field

We operate one well at Vermilion 170 which flows to a Company-owned and operated production platform at the same location. Based on current production and decline rates, we have determined the need to place our Vermilion 170 well on compression in 2014, at a cost of $1.4 million, net to the Company. As of December 31, 2013, we had incurred all of the $1.4 million to design, build and install the compressor.

In January 2013, sustained casing pressure was identified between the production tubing and the production casing at our Vermilion 170 well. Diagnostic tests revealed that the production tubing had parted downhole requiring a workover of the well. Well production was shut-in and the original tubing and casing were successfully removed. Operations were conducted to replace the tubing and restore the well to production in June 2013. For the year ended December 31, 2013, approximately $12.0 million was spent on these workover operations, 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. This well reached payout in 2012. We will continue producing this well as long as it is economical.

In September 2012 and December 2012, due to the decline in production and high water levels from our Ship Shoal 263 well, our reservoir engineer revised his estimated net proved natural gas and oil reserves from this well. As a result, the net book value of our Ship Shoal 263 well exceeded the future undiscounted cash flows associated with its reserves. Accordingly, we recognized an impairment expense of approximately $12.0 million during the year ended December 31, 2012 for this well.

On July 30, 2013, we spud our South Timbalier 17 prospect in state of Louisiana offshore waters, and on August 22, 2013 we announced a successful well. The well was drilled to a total measured depth of approximately 11,400 feet and the wireline logs of the well indicate the presence of hydrocarbons. We are proceeding with development, including installation of production facilities. Estimated costs net to Contango to drill, complete and bring this well to full production status are $12.6 million, $10.3 million of which has been incurred as of December 31, 2013. 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. We expect this well to commence production in mid-2014.

In December 2013, we spud our Ship Shoal 255 prospect. We have budgeted $23.0 million to drill this well, with total drilling operations forecasted to conclude in March 2014. Contingent on success, additional capital will be invested to complete and tie-in the well. We will transport the new production through our nearby platform at Ship Shoal 263. We have currently classified the platform as unproved properties, as its cost is expected to be recovered through our Ship Shoal 255 prospect.

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 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 now own 16 offshore lease blocks.

Prior Year Activities

In July 2012, we spud our Ship Shoal 134 and South Timbalier 75 prospects. In October 2012, we announced that we had reached total depth on each and no commercial hydrocarbons were found. The Company has plugged and abandoned both wells. We incurred approximately $50.0 million to drill, plug and abandon these wells, including approximately $6.6 million in leasehold costs.

In July 2011, we recompleted our Eloise South well uphole in the Cib-Op sands as our Dutch #5 well, at a cost of approximately $5.7 million, while in January 2012 we recompleted our Eloise North well uphole in the Cib-Op sands as our Mary Rose #5 well, at a cost of approximately $0.5 million. The Mary Rose #5 is currently flowing intermittently awaiting compression.

Onshore Properties

Our onshore areas of operation consist primarily of:

- Southeast Texas. As of December 31, 2013, our Southeast Texas region included approximately 42,580 gross (26,476 net) acres, proven reserves of 52.3 Bcfe, and 79 gross (44.3 net) producing wells. Crimson has actively developed this area since 2008, primarily focusing on conventional wells in the Yegua and Cook Mountain sands in Liberty County until 2012. In 2012, Crimson shifted its focus to the horizontal development of the Woodbine formation in Madison and Grimes counties, where there has recently been significant industry activity pursuing the Woodbine and Eagle Ford Shale oil plays near our leasehold positions. During 2013, Crimson, and then Contango, drilled 12 gross (eight net) wells on acreage targeting the Woodbine formation. We will continue our focus on further developing our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2014. We currently have approximately 19,000 net acres, with a multi-year inventory of potential drilling locations, in Madison and Grimes counties, which includes the Woodbine, Eagle Ford Shale and Georgetown formations.

On December 31, 2013, we sold to an independent third party approximately 7.1% of our interest in all developed and undeveloped properties in Madison and Grimes Counties. The sales price of $20 million is subject to a purchase price adjustment, based on production and operating expenses between the effective date of July 1, 2013 and the closing date of December 31, 2013. The current estimated sales price after preliminary adjustments is $20.4 million, or $91,007 per flowing barrel of equivalent daily production and $47.32 per equivalent barrel of proved reserves.

- South Texas. As of December 31, 2013, our South Texas region included approximately 105,364 gross (55,885 net) acres, proven reserves of 63.3 Bcfe, and 274 gross (144.7 net) producing wells. Of this, approximately 25,880 gross (13,978 net) acres are targeting the Buda and Eagle Ford Shale plays, approximately 80% of which is held by production. Crimson began development of the Eagle Ford Shale in Bee County in 2010 and in Karnes, Zavala and Dimmit counties in 2011. During 2013, Contango and Crimson drilled six gross operated wells (three net) and one gross non-operated well (0.25 net) in the Buda formation in Zavala and Dimmit counties. Six of the wells were successful, while one was a mechanical failure which may be side tracked in the future. Initial thirty-day average production rates for each of the first five wells was 730 boed while the sixth well continues to clean up. We have one additional well in process at December 31, 2013 and expect to have at least one rig running full-time in 2014. Our estimated net proven Buda/Eagle Ford reserves in this area were 23.5 Bcfe, comprised of 74.4% liquids, with 17 gross (8.9 net) producing wells, as of December 31, 2013.

The remaining 79,484 gross (41,907 net) acres in South Texas are located in our conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved conventional reserves in this area were 39.8 Bcfe, comprised of 76.3% gas, with 257 gross (135.8 net) producing wells, as of December 31, 2013.

- Other (East Texas). As of December 31, 2013, our East Texas region included approximately 7,904 gross (4,833 net) acres primarily in San Augustine County, proven reserves of 1.5 Bcfe comprised of 99% gas, and eight gross (3.9 net) producing wells. Crimson actively developed the Haynesville and Mid-Bossier Shales in this area in 2009 through 2011 during a more favorable natural gas price environment. We 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. During 2014, we will initiate development of the shallower liquids rich James Lime formation on our acreage in San Augustine County. We anticipate that we will drill up to two wells in that area during 2014, where the offset operator has experienced excellent results in recent drilling. As of December 31, 2013, approximately 80% of our acreage in East Texas is held by production.

- Other (Tuscaloosa Marine Shale). We own a 25% non-operated working interest in the Crosby 12H-1 well in Wilkinson County, Mississippi, targeting the TMS, an oil-focused shale play in central Louisiana and Mississippi. This well is operated by Goodrich Petroleum Company LLC ("Goodrich"). As of December 31, 2013, the Crosby 12H-1 well was producing at an 8/8ths rate of approximately 200 barrels of oil per day, with cumulative production of approximately 136,000 barrels of oil from the commencement of production through December 31, 2013.

In addition, as of December 31, 2013, we had leased approximately 40,492 gross (29,065 net) undeveloped acres in the TMS. To date, we have elected to participate in three non-operated wells (excluding the Crosby 12H-1 discussed above) where our acreage has been pooled into units: (i) the Goodrich-operated CMR/Foster Creek 20-7H #1 well, where we own less than a 1% working interest; (ii) the Goodrich-operated Huff 18-7H #1 well, where we own approximately a 3% working interest; and (iii) the Goodrich-operated Horseshoe Hill #1 well, where our working interest is still being determined and which will likely be drilled in 2014. We plan to continue to evaluate participation in third-party operated

5

wells with a small working interest as a means to obtain data from these wells to assist us in evaluating our TMS acreage and develop a plan for potentially drilling and operating future wells.

- Other (Colorado). We hold approximately 16,080 gross (11,229 net) acres in the DJ Basin in Colorado (mostly in Adams and Weld counties). 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. Substantially all of our net acres in the Niobrara Shale are held by production. 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.
- Other. As of December 31, 2013, we held approximately 3,302 gross (621 net) acres in small non-operating working interests in the Fenton field area of Calcasieu Parish, Louisiana and a minor crude oil property in Mississippi.

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, $23.1 million was received in September 2013, $5.4 million was received in February 2014, 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 December 31, 2013, we had invested approximately $46.9 million in Exaro.

Exaro has 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 will be comprised of the $182.5 million investment described above, debt, and cash flow from operations. Encana will continue to be the operator of the field. Upon investing the full amount of the $380 million, Exaro will have earned 32.5% of Encana's working interest in a defined joint venture area that comprises approximately 5,760 gross acres.

As of December 31, 2013 the Exaro-Encana venture had 83 new wells on production, producing at a rate of approximately 38 Mmcfed, net to Exaro, plus an additional 14 wells that are either in the completion or fracture stimulation phase. Encana has indicated that they expect to have three drilling rigs running on this project during 2014. For the year ended December 31, 2013, the Company recognized a gain of approximately $2.3 million, net of tax expense of $1.2 million, as a result of its investment in Exaro. As of December 31, 2013, reserves attributable to our investment in Exaro were 41.7 Bcfe. We do not anticipate making any additional equity contributions during 2014. See Note 11 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 Southeast and South Texas 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.

Outlook

Our capital expenditure budget for 2014 is currently forecasted at approximately $216 million, and is expected to be funded primarily from internally generated cash flow. Our plans include the drilling of 47 gross wells (28 net). Expenditures planned for 2014 include:

- Gulf of Mexico - We forecast capital expenditures of approximately $39 million for 2014. The largest components of this amount include $23 million to drill our Ship Shoal 255 exploratory prospect and $12 million to commence drilling an additional exploratory well in the shallow waters of the Gulf of Mexico late in the year.
- Woodbine - We forecast capital expenditures of approximately $89 million in Madison and Grimes Counties to drill 19-20 wells. We currently anticipate 11 wells in our Force area, six wells in our Chalktown area and two wells in our Iola / Grimes area, all of which will target the Woodbine formation. Additionally, we will drill one or more additional wells to test other reservoir-maximization strategies in the area.
- Buda - We forecast capital expenditures of approximately $33 million in Zavala and Dimmit Counties to drill 14 operated and five non-operated wells targeting the Buda formation.
- James Lime - We forecast capital expenditures of approximately $9 million in St. Augustine County to drill two wells targeting the James Lime formation.
- Other - We also forecast spending an additional $46 million in 2014 on the acquisition of undeveloped acreage in existing and new areas, initial test wells on other formations in current areas or new acreage, on seismic data and for potential completion/facility costs on Gulf of Mexico prospects.

Discontinued Operations

Patara and Rexer Assets

In October 2009, the Company entered into a joint venture with Patara Oil & Gas LLC ("Patara") to develop Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company’s board of directors, was the Chief Executive Officer of Patara at the time. In May 2011, the Company sold to Patara its interest in the wells drilled under this joint venture program, as well as its interest in two wells we drilled in Texas (Rexer #1 and Rexer-Tusa #2).

Contango Mining Company

Contango Mining Company (“Contango Mining”), a wholly-owned subsidiary of the Company was initially formed in October 2009 for the purpose of engaging in exploration in the State of Alaska for gold and rare earth elements. Contango Mining held leasehold interests in native, Federal, and State of Alaska acreage. In November 2010, Contango ORE, Inc. ("CORE"), then another wholly-owned subsidiary of the Company, acquired the assets and acreage of Contango Mining in exchange for its common stock which was subsequently distributed to the Company’s stockholders. The Company also contributed $3.5 million in cash to CORE immediately prior to the distribution and no longer has an ownership in CORE.

We have accounted for these transactions as discontinued operations and have included the results of these operations in discontinued operations for all periods presented. See Note 18 to our Financial Statements - "Discontinued Operations" for a description of these transactions.

Title to Properties

From time to time, we are involved in legal proceedings relating to claims associated with ownership interests in our properties. We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, and liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed independent third party attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our natural gas and crude oil properties to secure our senior secured revolving credit facility. These mortgages and the related credit agreement contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 13 to our Financial

Statements "Long-Term Debt" for further information.

7

Marketing and Pricing

We currently derive our revenue principally from the sale of natural gas and oil. As a result, our revenues are determined, to a large degree, by prevailing natural gas and oil prices. We sell a portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to three years and crude oil and condensate production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for crude oil are tied to industry standard posted prices subject to negotiated price adjustments.

We utilize commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We use a series of swaps and costless collars to accomplish our commodity hedging strategy. Unrealized gains or losses will vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities and interest rates being hedged.

Price decreases would adversely affect our revenues, profits and the value of our proved reserves. Historically, the prices received for natural gas and oil have fluctuated widely. Among the factors that can cause these fluctuations are:

- The domestic and foreign supply of natural gas and oil
- Overall economic conditions
- The level of consumer product demand
- Adverse weather conditions and natural disasters
- The price and availability of competitive fuels such as heating oil and coal
- Political conditions in the Middle East and other natural gas and oil producing regions
- The level of LNG imports/exports
- Domestic and foreign governmental regulations
- Special taxes on production
- The loss of tax credits and deductions

Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. Major purchasers of our natural gas, oil and natural gas liquids for the year ended December 31, 2013, calculated on an equivalent basis, were ConocoPhillips Company (48%), Shell Trading US Company (16%), Sunoco, Inc. (9%), Enterprise Products Operating LLC (7%), and Exxon Mobil Oil Corporation (7%). This concentration of purchasers may increase our overall exposure to credit risk, and our purchasers will likely be similarly affected by changes in economic and industry conditions. Our financial condition and results of operations could be materially adversely affected if one or more of our significant purchasers fails to pay us or ceases to acquire our production on terms that are favorable to us. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

Competition

The oil and gas industry is highly competitive and we compete with numerous other companies. Our competitors in the exploration, development, acquisition and production business include major integrated oil and gas companies as well as numerous independent companies, including many that have significantly greater financial resources and in-house technical expertise.

The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining purchasers and transporters for the natural gas and crude oil we produce. There is also competition between producers of natural gas and crude oil and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing natural gas and crude oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Governmental Regulations and Industry Matters

Federal Income Tax

Federal income tax laws significantly affect our operations. The principal provisions affecting us are those that permit us, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, its domestic “intangible drilling and development costs" and to claim depletion on a portion of our domestic natural gas and oil properties and to claim a manufacturing deduction based on qualified production activities.

Industry Regulations

The availability of a ready market for crude oil, natural gas and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of crude oil, natural gas, and natural gas liquids production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of crude oil, natural gas and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or lack of an available natural gas pipeline in the area in which the well is located. State and federal regulations generally are intended to prevent waste of crude oil, natural gas, and natural gas liquids, protect rights to produce crude oil, natural gas and natural gas liquids between owners in a common reservoir, control the amount of crude oil, natural gas and natural gas liquids produced by assigning allowable rates of production, and protect the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the U.S. oil and gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Crude Oil, Natural Gas and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of crude oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws, which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of crude oil, natural gas and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938 (the "NGA"), the Federal Energy Regulatory Commission (the "FERC") regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC's jurisdiction over natural gas transportation.

Under the provisions of the Energy Policy Act of 2005 (the “2005 Act”), the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission (the “CFTC”) also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. For example, on December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704 as clarified in orders on clarification and rehearing. In addition, to the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC's regulations could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978 (the "NGPA"), the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required interstate pipelines, among other things, to perform "open access" transportation of gas for others, "unbundle" their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular interstate pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC's other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of crude oil and natural gas liquids transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

Environmental and Occupational Health and Safety Matters

Our crude oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment, or otherwise relating to environmental protection. Numerous governmental authorities, including the U.S.

Environmental Protection Agency (the “EPA”) and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may require the acquisition of a permit to conduct drilling and other regulated activities, restrict the types, quantities and concentration of various substances that may be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from current or former operations; impose specific health and safety criteria addressing worker protection; and impose substantial liabilities for pollution resulting from production and drilling operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of orders enjoining some or all of our operations in affected areas. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue in the future, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental actions are taken that result in more stringent and costly well drilling, construction, completion, water management activities, waste handling, storage, transport, disposal or remediation requirements, our business and prospects could be materially and adversely affected.

Our domestic natural gas and oil operations, including those involving federal leases in the U.S. Gulf of Mexico, are subject to extensive federal and state regulation and imposition of environmental liabilities or possible interruption or termination of leasing activities by governmental authorities. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, (“CERCLA”), also known as the “Superfund Law”, and similar state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These potentially responsible persons include the current or past owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate wastes that are subject to the federal Resource Conservation and Recovery Act, as amended (the “RCRA”), and comparable state statutes. The RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous wastes, and the EPA and analogous state agencies stringently enforce the approved methods of management and disposal of these wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of crude oil and natural gas from regulation as hazardous wastes, we can provide no assurance that this exemption will be preserved in the future. Repeal or modification of this exclusion or similar exemptions under federal or state law could increase the amount of waste we are required to manage and dispose of as hazardous waste rather than non-hazardous waste, and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general. In any event, these excluded wastes are subject to regulation as nonhazardous wastes.

We currently own, lease or operate numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have used good operating and waste disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the petroleum hydrocarbons or wastes disposed thereon may be subject to the CERCLA, RCRA and analogous state laws as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, which may impose strict, joint and several liability, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The Clean Air Act, as amended (the “CAA”), and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of crude oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Based on findings made by the EPA in December 2009 that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources, should such sources exceed threshold emission levels. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, which include the majority of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has, from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

The Federal Water Pollution Control Act, as amended (the "Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. Any such discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The disposal of oil and natural gas wastes into underground injection wells are subject to the Safe Drinking Water Act, as amended, or SDWA, and analogous state laws. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities that may be injected, and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for alternative water supplies, property damages and personal injuries. While we believe that we have obtained the necessary permits from the applicable regulatory agencies for our underground injection wells and that we are in substantial compliance with applicable permit conditions and federal and state rules, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations, which costs could be significant. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies, including the Texas Railroad Commission, have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

The Oil Pollution Act of 1990 (the “OPA”) and regulations thereunder impose a variety of regulations on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA applies to vessels, onshore facilities, and offshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities and lessees and permittees of offshore leases may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. In addition, to the extent the Company’s offshore lease operations affect state waters, the Company may be subject to additional state and local clean-up requirements or incur liability under state and local laws. The OPA also imposes ongoing requirements on responsible parties, including preparation of oil spill response plans for responding to a worst-case discharge of oil into waters of the U.S., and proof of financial responsibility to cover at least some costs in a potential spill. The Company believes that it currently has established adequate proof of financial responsibility in the form of a Certificate of Financial Responsibility ("COFR") for its offshore facilities. However, the Company cannot predict whether significantly higher COFR amounts under any future OPA amendments will result in the imposition of substantial additional annual costs to the Company in the future or otherwise materially adversely affect the Company. The impact, however, should not be any more adverse to the Company than it will be to other similarly situated or less capitalized owners or operators in the Gulf of Mexico.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemical additives under pressure into targeted subsurface formations to stimulate production. We routinely use hydraulic fracturing techniques in many of our completion programs. Hydraulic fracturing typically is regulated by state oil and gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act ("SDWA"), regarding hydraulic fracturing involving the use of diesel fuels and issued revised permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency continues to project the issuance of a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states, including Texas, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards in 2014. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and issued a report in 2011 on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale gas development. Also, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SWDA or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our hydraulic fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party pollution claims in accordance with, and subject to the terms of such policies.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the federal Bureau of Land Management ("BLM"), are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Environmental laws such as the Endangered Species Act, as amended ("ESA"), may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of numerous species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Impact of Deepwater Horizon Incident

In response to an April 2010 fire and explosion aboard the Deepwater Horizon drilling rig and resulting oil spill from the Macondo well operated by a third party in ultra-deepwater in the Gulf of Mexico, federal authorities have pursued a series of regulatory initiatives to address the direct impact of that incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through 2013, the federal government, acting through the U.S. Department of the Interior ("DOI") and its implementing agencies, BOEM and BSEE, has issued various rules, Notices to Lessees and Operators ("NTLs") and temporary drilling moratoria that impose or result in added environmental and safety measures upon exploration, development and production operators in the Gulf of Mexico. These new regulatory requirements include the following:

- The Environmental NTL, which imposes more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements;
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes and also requires certifications of compliance from senior corporate officers;

- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams; and
- The Workplace Safety Rule, which requires operators to employ a comprehensive safety and environmental management system, known as "SEMS," to reduce human and organizational errors as root causes of work-related accidents and offshore spills, which rule was subsequently amended in April 2013 to require operators to, among other things, establish procedures providing all personnel with "stop work" authority, develop protocols as to whom at the facility has the ultimate operational safety and decision-making authority, and establish an independent auditing regimen whereby facility audits are conducted by a service provider accredited by BSEE that is unaffiliated with the operator.

These regulatory initiatives may serve to effectively delay the pace of exploration and production operations in the Gulf of Mexico due to adjustments in operating procedures and certification practices as well as increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits. These new requirements also increase the cost of preparing permit applications and will increase the cost of each new well, particularly for wells drilled in deeper waters on the Outer Continental Shelf. We could become subject to fines, penalties or orders requiring us to modify or suspend our operations in the Gulf of Mexico if we fail to comply with these requirements. Legislation has been considered that would require each company doing business in the Gulf of Mexico to establish and maintain a significantly higher COFR amount to pay for cleanup costs and damages arising from oil spills under the OPA, which, if ever adopted, could cause us and similarly situated offshore operators to incur significantly higher operating costs or adversely affect the ability to continue to conduct offshore operations. In any event, if similar oil spill incidents were to occur in the future in the Gulf of Mexico or elsewhere where we conduct operations, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental regulatory initiatives regarding offshore oil and gas exploration and development activities, which any one or more of such events could have a material adverse effect on our volume of business as well as our financial position, results of operations and liquidity. Our ability to obtain insurance or additional insurance coverage on commercially reasonable terms to protect against any increase in liability is uncertain.

Other Laws and Regulations

Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of natural gas and oil including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the Company's properties and to limit the allowable production from the successful wells completed on the Company's properties, thereby limiting the Company's revenues.

The BOEM administers the natural gas and oil leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The BOEM holds a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the BOEM changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers. At the end of lease operations, oil and gas lessees must plug and abandon wells, remove platforms and other facilities, and clear the lease site sea floor. The BOEM requires companies operating on the Outer Continental Shelf to obtain surety bonds to ensure performance of these obligations. As an operator, the Company is required to obtain surety bonds of $200,000 per lease for exploration and $500,000 per lease for developmental activities.

Risk and Insurance Program

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We continuously monitor regulatory changes and regulatory responses and their impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows. Changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico could lead to tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, including possible increases in liability caps for claims of damages from oil spills.

We maintain significant insurance coverage attributable to our net share of any potential financial losses occurring as a result of potential perils, including well control coverage of up to $100 million on certain wells, which covers control of well, pollution cleanup and consequential damages. We also maintain $150 million of general liability coverage, which covers pollution cleanup, consequential damages coverage, and third party personal injury and death, and $150 million of Oil Spill Financial Responsibility coverage, which covers additional pollution cleanup and third party claims coverage.

Health, Safety and Environmental Program

Our Health, Safety and Environmental ("HS&E") Program is supervised by an operating committee of senior management to insure compliance with all state and federal regulations. In addition, to support the operating committee, we have contracted with J. Connor Consulting ("JCC") to manage our regulatory process relating to our offshore assets. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico regulatory process, preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills to oil and gas companies and pipeline operators.

In addition, for our Gulf of Mexico operations, we have a Regional Oil Spill Plan in place with the BOEM. Our response team is trained annually and is tested through annual spill drills given by the BOEM. In addition, we have in place a contract with O'Brien's Response Management ("O'Brien's"). O'Brien's maintains a 24/7 manned incident command center located in Slidell, LA. Upon the occurrence of an oil spill, the Company's spill program is initiated by notifying O'Brien's that we have an emergency. While the Company would focus on source control of the spill, O'Brien's would handle all communication with state and federal agencies as well as U.S. Coast Guard notifications.

If an offshore spill were to occur, we have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs. CGA specializes in onsite control and cleanup and is on 24 hour alert with equipment currently stored at six bases (Ingleside and Galveston, TX; Lake Charles, Houma, and Venice, LA; and Pascagoula, MS), and is opening new sites in Leeville, Morgan City and Harvey, LA. The CGA equipment stockpile is available to serve member oil spill response needs including blowouts; open seas, near shore and shallow water skimming; open seas and shoreline booming; communications; dispersants; boat spray systems to apply dispersants; wildlife rehabilitation; and a forward command center. CGA has retainers with an aerial dispersant company and a company that provides mechanical recovery equipment for spill responses.

In addition to being a member of CGA, the Company has contracted with Wild Well Control for source control at the wellhead, if required. Wild Well Control is one of the world's leading providers of firefighting, well control, engineering, and training services.

We also have a full time manager of health, safety and environmental matters that supports our operations and oversees the implementation of our onshore HS&E policies.

Safety and Environmental Management System

We have developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the Outer Continental Shelf ("OCS"), as required by the BSEE. Our SEMS program identifies, addresses, and manages safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company has established goals, performance measures, training, accountability for its implementation, and provides necessary resources for an effective SEMS, as well as reviews the adequacy and effectiveness of the SEMS program. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. We have contracted with Island Technologies Inc. to manage our SEMS program for production operations.

The BSEE enforces the SEMS requirements through regular audits. Failure of an audit may force us to shut-in our Gulf of Mexico operations until the audit finding is resolved.

Employees

On December 31, 2013, we had 79 full time employees, of which 21were field personnel. Following our merger with Crimson, we terminated our human resources relationship with Insperity, Inc. and began to manage the human resources function internally. We have been able to attract and retain a talented team of industry professionals that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets and also to increase our proved reserves and production through exploitation of our existing asset base, as well as the continuing identification, acquisition, and development of new growth opportunities. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

In addition to our employees, we use the services of independent consultants and contractors to perform various professional services. We generally rely on JEX for offshore prospect generation and evaluation. As a working interest owner, we rely on certain outside operators to drill, produce and market our natural gas and oil where we are a non-operator. In prospects where we are the operator, we rely on drilling contractors to drill and sometimes rely on independent contractors to produce and market our natural gas and oil. In addition, we frequently utilize the services of independent contractors to perform field and on-site drilling and production operation services and independent third party engineering firms to evaluate our reserves.

Directors and Executive Officers

See Item 10. “Directors and Executive Officers of the Registrant,” which information is incorporated herein by reference.

Corporate Offices

Effective October 1, 2013, we moved our corporate offices to 717 Texas Avenue in downtown Houston, Texas, under a lease that expires March 31, 2019. Rent, including parking, related to this new office space for the three months ended December 31, 2013 was approximately $0.3 million. We remain responsible for the rent at our previous corporate office at 3700 Buffalo Speedway in Houston, Texas, through February 29, 2016. Rent, including parking, related to this previous office space for the year ended December 31, 2013 was approximately $0.7 million. Effective January 1, 2014, we subleased our previous corporate offices through February 29, 2016 and expect to recover the substantial majority of the rent we pay at that location.

Code of Ethics

We adopted a Code of Ethics for senior management in December 2002. In January 2014, our board of directors adopted a new Code of Business Conduct and Ethics ("Code of Conduct") that applies to all directors, officers and employees of the Company. Our Code of Conduct is available on the Company's website at www.contango.com. Any shareholder who so requests may obtain a copy of the Code of Conduct by submitting a request to the Company's corporate secretary at the address on the cover of this Form 10-K/A. Changes in and waivers to the Code of Conduct for the Company's directors, chief executive officer and certain senior financial officers will be posted on the Company's website within five business days and maintained for at least 12 months. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Report on Form 10-K/A.

Available Information

You may read and copy all or any portion of this report on Form 10-K/A, our quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, without charge at the office of the Securities and Exchange Commission (the “SEC”) in Public Reference Room, 100 F Street NE, Washington, DC, 20549. Information regarding the operation of the public reference rooms may be obtained by calling the SEC at 1-800-SEC-0330. In addition, filings made with the SEC electronically are publicly available through the SEC's website at http://www.sec.gov, and at our website at http://www.contango.com. This report on Form 10-K/A, including all exhibits and amendments, has been filed electronically with the SEC.

Seasonal Nature of Business

The demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies, and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand.

Item 1A. Risk Factors

In addition to the other information set forth elsewhere in this Form 10-K/A, you should carefully consider the following factors when evaluating the Company. An investment in the Company is subject to risks inherent in our business. The trading price of the shares of the Company is affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in the Company may decrease, resulting in a loss.

RISK FACTORS RELATING TO OUR BUSINESS

We have no ability to control the market price for natural gas and oil. Natural gas and oil prices fluctuate widely, and a substantial or extended decline in natural gas and oil prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on the business, the results of operations and financial condition of the Company.

Our revenues, profitability and future growth depend significantly on natural gas and crude oil prices. The markets for these commodities are volatile and prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. Lower prices may also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

- Overall economic conditions.
- The domestic and foreign supply of natural gas and oil.
- The level of consumer product demand.
- Adverse weather conditions and natural disasters.
- The price and availability of competitive fuels such as LNG, heating oil and coal.
- Political conditions in the Middle East and other natural gas and oil producing regions.
- The level of LNG imports and any LNG exports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- Access to pipelines and gas processing plants.
- The loss of tax credits and deductions.

A substantial or extended decline in natural gas and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us.

Part of our strategy involves drilling in new or emerging plays; therefore, our drilling results in these areas are not certain.

The results of our drilling in new or emerging plays, such as in our East Texas and South Texas resource plays and the horizontal redevelopment of the Woodbine and other formations in Southeast Texas, are more uncertain than drilling results in areas that are more developed and with longer production history. Since new or emerging plays and new formations have limited production history, we are less able to use past drilling results in those areas to help predict our future drilling results. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or crude oil, natural gas and natural gas liquids price declines. To the extent we are unable to execute our expected drilling program in these areas, our return on investment may not be as attractive as we anticipate and our common stock price may decrease. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

Initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Our future cash flows are subject to a number of variables, including the level of production from existing wells. Initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates. As a result, we generally must locate and develop or acquire new crude oil or natural gas reserves to offset declines in these initial production rates. If we are unable to do so, these declines in initial production rates may result in a decrease in our overall production and revenue over time.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of undeveloped acreage and a decline in our crude oil, natural gas and natural gas liquids reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of crude oil, natural gas and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our senior secured revolving credit agreement. Our cash flow from operations and access to capital is subject to a number of variables, including:

- Our proved reserves.
- The level of crude oil, natural gas and natural gas liquids we are able to produce from existing wells.
- The prices at which crude oil, natural gas and natural gas liquids are sold.
- Our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower crude oil, natural gas and natural gas liquids prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our credit agreements contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base redetermination results in a lower borrowing base under our senior secured revolving credit agreement, we may be unable to obtain financing otherwise available under our senior secured revolving credit agreement. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Capital Resources and Liquidity."

Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our crude oil, natural gas and natural gas liquids reserves.

We assume additional risk as operator in drilling high pressure and high temperature wells in the Gulf of Mexico.

We continue to drill and operate exploration wells in the Gulf of Mexico. Drilling activities are subject to numerous risks, including the significant risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. Drilling costs could be significantly higher if we encounter difficulty in drilling offshore exploration wells. The Company's drilling operations may be curtailed, delayed, canceled or negatively impacted as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or we may not recover all or any of our investment. The risk of significant cost overruns, curtailments, delays, inability to reach our target reservoir and other factors detrimental to drilling and completion operations may be higher due to our inexperience as an operator.

We rely on third-party operators to operate and maintain some of our wells, production platforms, pipelines and processing facilities and, as a result, we have limited control over the operations of such facilities. The interests of an

operator may differ from our interests.
We depend upon the services of third-party operators to operate some production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. We have limited influence over the conduct of operations by third-party operators. As a result, we have little control over how frequently and how long our production is shut-in when production problems, weather and other production shut-ins occur. Poor performance on the part of,

or errors or accidents attributable to, the operator of a project in which we participate may have an adverse effect on our results of operations and financial condition. Also, the interest of an operator may differ from our interests.
Repeated offshore production shut-ins can possibly damage our well bores.
Our offshore well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill additional wells.
Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.
Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Further, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.
Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.
There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.
In order to prepare these estimates, our independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.
Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value.
Approximately 19% of our total estimated proved reserves at December 31, 2013 were proved undeveloped reserves.
Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil, natural gas and natural gas liquids reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs

are accurate, that development will occur as scheduled or that the results of such development will be as estimated.
The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated crude oil, natural gas and natural gas liquids reserves.
You should not assume that the present value of future net revenues from our proved reserves referred to in this report is the current market value of our estimated crude oil, natural gas and natural gas liquids reserves. In accordance with the requirements

of the SEC, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2013 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2013. For our offshore condensate and natural gas liquids volumes, the average West Texas Intermediate (Cushing) posted price was $97.33 per barrel. For our onshore crude oil and natural gas liquids volumes, the average West Texas Intermediate (Plains) posted price was $93.42 per barrel. For our natural gas volumes, the average Henry Hub spot price was $3.67 per MMBtu. The following sensitivity analyses for condensate, crude oil and natural gas do not include the volatility reducing effects of our derivative hedging instruments in place at December 31, 2013. If condensate and crude oil prices were $1.00 per Bbl lower than the prices used, our PV 10 as of December 31, 2013 would have decreased from $987.2 million to $979.1 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV 10 as of December 31, 2013, would have decreased from $987.2 million to $972.7 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock. A reconciliation of our Standardized Measure to PV 10 is provided under "Item 2. Properties - Proved Reserves".

Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of crude oil, natural gas and natural gas liquids. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. For example, we have over 4,000 square miles of 3D data in the South Texas and Gulf Coast regions. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing crude oil, natural gas and natural gas liquids are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for crude oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- explosions and blowouts;
- pipe or cement failures;
-

environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment;

- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages of skilled personnel;

- shortages or delivery delays of equipment and services or of water used in hydraulic fracturing activities;
- compliance with environmental and other regulatory requirements;
- natural disasters; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

The potential lack of availability or high cost of drilling rigs, equipment, supplies, personnel and crude oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

When the prices of crude oil, natural gas and natural gas liquids increase, or the demand for equipment and services is greater than the supply in certain areas, we typically encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operations and financial condition.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of crude oil, natural gas and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a portion of our crude oil, natural gas and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial instruments to hedge commodity price exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We typically use a combination of puts, swaps and costless collars.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position-limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions on us is uncertain at this time. The Dodd-Frank Act and regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

We may incur substantial impairment of proved properties.

If management's estimates of the recoverable proved reserves on a property are revised downward or if oil and/or natural gas prices decline, we may be required to record non-cash impairment write-downs in the future, which would result in a negative impact to our financial results. Furthermore, any sustained decline in oil and/or natural gas prices may require us to make further impairments. We review our proved oil and gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and natural gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value.

Management's assumptions used in calculating oil and gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

Production activities in the Gulf of Mexico increase our susceptibility to pollution and natural resource damage.

A blowout, rupture or spill of any magnitude would present serious operational and financial challenges. All of the Company's operations in the Gulf of Mexico shelf are in water depths of less than 300 feet and less than 50 miles from the coast. Such proximity to the shore-line increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the CAA that establish PSD and Title V permit reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations.

While, Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The natural gas and oil business involves many operating risks that can cause substantial losses and our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The natural gas and oil business involves a variety of operating risks, including:

- Blowouts, fires and explosions.
- Surface cratering.
- Uncontrollable flows of underground natural gas, oil or formation water.
- Natural disasters.
- Pipe and cement failures.
- Casing collapses.
- Stuck drilling and service tools.
- Reservoir compaction.
- Abnormal pressure formations.
- Environmental hazards such as natural gas leaks, oil spills, pipeline ruptures or discharges of toxic gases.
- Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
- Repeated shut-ins of our well bores could significantly damage our well bores.
- Required workovers of existing wells that may not be successful.

If any of the above events occur, we could incur substantial losses as a result of:

- Injury or loss of life.
- Reservoir damage.
- Severe damage to and destruction of property or equipment.
- Pollution and other environmental damage.
- Clean-up responsibilities.
- Regulatory investigations and penalties.
- Suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If we were to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect our ability to conduct operations. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. We may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Our ability to market our natural gas and oil may be impaired by capacity constraints and equipment malfunctions on the platforms, gathering systems, pipelines and gas plants that transport and process our natural gas and oil.

All of our natural gas and oil is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or our transportation capacity is materially restricted or is unavailable in the future, our ability to market our natural gas or oil could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on our financial condition and results of operations. Further, repeated shut-ins of our wells could result in damage to our well bores that would impair our ability to produce from these wells and could result in additional wells being required to produce our reserves.

If our access to sales markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory crude oil, natural gas and natural gas liquids transportation arrangements may hinder our access to crude oil, natural gas and natural gas liquids markets or delay our production. The availability of a ready market for our crude oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for and supply of crude oil, natural gas and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our crude oil, natural gas and natural gas liquids may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

We may not have title to our leased interests and if any lease is later rendered invalid, we may not be able to proceed with our exploration and development of the lease site.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is to not incur the expense of retaining title lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of JEX and others to perform the field work in examining records in the appropriate governmental, county or parish clerk's office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well the operator of the well will typically obtain a preliminary title review of the drillsite lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may not have been cured by the operator of such wells. It does happen, from time to time, that the examination made by title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect. It may also happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Competition in the natural gas and oil industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with a broad range of natural gas and oil companies in our exploration and property acquisition activities. We also compete for the equipment and labor required to operate and to develop these properties. Many of our competitors have substantially greater financial resources than we do. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties. Further, they may be able to evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil and to acquire additional properties in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating for a much longer time than we have and have substantially larger staffs. We may not be able to compete effectively with these companies or in such a highly competitive environment.

Proposed United States federal budgets and pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The federal administration has released repeated budget proposals over the past few years which include numerous proposed tax changes. The proposed budgets and legislation would repeal many tax incentives and deductions that are currently used by oil and gas companies in the United States and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law, taxes on the E&P industry would increase, which could have a negative impact on our results of operations and cash flows. Although these proposals initially were made in 2009, none have become law. It is still, however, the federal administration's stated intention to enact legislation to repeal tax incentives and deductions and impose new taxes on oil and gas companies.

We are subject to stringent laws and regulations, including environmental requirements that can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to numerous federal, state and local laws and regulations governing the operation and maintenance of our facilities, the discharge of materials into the environment and environmental protection. Failure to comply with such rules and regulations could result in the assessment of substantial penalties, imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. These laws and regulations:

- Require that we obtain permits before commencing drilling or other regulated activities;
- Restrict the substances that can be released into the environment in connection with drilling and production activities;
- Limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas;
- Require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- Apply specific health and safety criteria addressing worker protection.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain only limited insurance coverage for sudden and accidental environmental damages. Accordingly, we may be subject to liability, or we may be required to cease production from properties in the event of environmental damages. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed and any such changes could have an adverse effect on our business and results of operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority under the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and issued revised permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. Also, in November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency continues to project the issuance of a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states have adopted or are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and issued a report in 2011 on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale gas development. Also, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

More stringent regulatory initiatives relating to offshore exploration and production activities may have an adverse effect on our results of operations, financial position and liquidity.

In response to an April 2010 fire and explosion aboard the Deepwater Horizon drilling rig and resulting oil spill from the Macondo well operated by a third party in ultra-deepwater in the Gulf of Mexico, federal authorities have pursued a series of regulatory initiatives to address the direct impact of that incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through 2013, the federal government, acting through the DOI and its implementing agencies, the BOEM and BSEE, has issued various rules, NTLs and temporary drilling moratoria that impose or result in added environmental and safety measures upon exploration, development and production operators in the Gulf of Mexico. These new regulatory requirements include the following:

- The Environmental NTL, which imposes more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements;
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes and also requires certifications of compliance from senior corporate officers;
- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams; and
- The Workplace Safety Rule, which requires operators to employ a comprehensive safety and environmental management system, often referred to as SEMS, to reduce human and organizational errors as root causes of work-related accidents and offshore spills, which rule was subsequently amended as published on April 5, 2013 (sometimes referred to as the “SEMS II” rule) to require operators to, among other things, establish procedures providing all personnel with “stop work” authority, develop protocols as to whom at the facility has the ultimate operational safety and decision-making authority, and establish an independent auditing regimen whereby facility audits are conducted by a service provider accredited by BSEE that is unaffiliated with the operator.

These regulatory initiatives may serve to effectively slow down the pace of drilling and production operations in the Gulf of Mexico due to adjustments in operating procedures and certification practices as well as increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits. These new requirements also increase the cost of preparing permit applications and will increase the cost of each new well, particularly for wells drilled in deeper waters on the Outer Continental Shelf. We could become subject to fines, penalties or orders requiring us to modify or suspend our operations in the Gulf of Mexico if we fail to comply with these requirements. Also, legislation has been considered that would require each company doing business in the Gulf of Mexico to establish and maintain a significantly higher COFR amount to pay for cleanup costs and damages arising from oil spills under the OPA, which, if ever adopted, could cause us and similarly situated offshore operators to incur significantly higher operating costs or adversely affect the ability to continue to conduct offshore operations. In any event, if similar oil spill incidents were to occur in the future in the Gulf of Mexico or elsewhere where we conduct operations, the United States or other countries could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental regulatory initiatives regarding offshore oil and gas exploration and development activities, which any one or more of such events could have a material adverse effect on our volume of business as well as our financial position, results of operations and liquidity. Our ability to obtain insurance or additional insurance coverage on commercially reasonable terms to protect against any increase in liability may be precluded or infeasible.

The BSEE has implemented much more stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. They are responsible for leading the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well design and workplace safety to corporate accountability. One of the many reforms includes implementing a SEMS program. This program requires operators to identify, address, and manage safety and environmental hazards during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. Failure to comply with the SEMS program may force us to cease operations in the Gulf of Mexico.

Additionally, the OCS Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and a periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills, or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production, and pipeline safety. Upon detecting a violation, the inspector issues an Incident of Noncompliance ("INC") to the operator and uses one of two main enforcement actions (warning or shut-in), depending on the severity of the violation. If the violation is not severe or threatening, a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility. The violation must be corrected before the operator is allowed to resume the activity in question.

In addition to the enforcement actions specified above, the BSEE can assess a civil penalty of up to $40,000 per violation per day if: 1) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or 2) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

We are highly dependent on our senior management team, JEX, our exploration partners, third-party consultants and engineers, and other key personnel and any failure to retain the services of such parties could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. The loss of key members of our management team, JEX or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves.
- Exploration potential.
- Future natural gas and oil prices.
- Operating costs.
- Potential environmental and other liabilities and other factors.
- Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are necessarily inexact and their accuracy inherently uncertain and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies.
- Unanticipated costs.
- Diversion of resources and management attention from our exploration business.

- Entry into regions or markets in which we have limited or no prior experience.
- Potential loss of key employees of the acquired organization.

We may be unable to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations. The difficulties of integrating these assets and properties present numerous risks, including:

- Acquisitions may prove unprofitable and fail to generate anticipated cash flows.
- We may need to (i) recruit additional personnel and we cannot be certain that any of our recruiting efforts will succeed and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management.
- Our management's attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing crude oil, natural gas and natural gas liquids properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing crude oil, natural gas and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

RISK FACTORS RELATED TO AN INVESTMENT IN OUR COMMON STOCK

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for crude oil, natural gas and natural gas liquids;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;
- general market, economic and political conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us, our significant stockholders or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Also, the provisions of our senior secured revolving credit agreement and second lien credit agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 31, 2013, we had 135,107 options to purchase shares of our common stock outstanding, all of which were fully vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;
- require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;
- require business at special meetings to be limited to the stated purpose or purposes of that meeting;
- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;
- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and
- permit directors to fill vacancies in our board of directors.

We are subject to the Delaware business combination law.

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a "business combination" with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a "business combination" as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an "interested stockholder" as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation's voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or
- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law.

RISK FACTORS RELATED TO OUR RECENTLY COMPLETED MERGER

Uncertainties associated with the Merger may cause a loss of management personnel and other key employees.

We are dependent on the experience and industry knowledge of our officers and other key employees to execute our business plans. The combined company's success depends in part upon the ability of the Company to retain key management personnel and other key employees. Current and prospective employees may experience uncertainty about their roles within the combined company following the Merger, which may have an adverse effect on our ability to attract or retain key management and other key personnel. Accordingly, no assurance can be given that we will be able to attract or retain key management personnel and other key employees.

The failure to integrate successfully the businesses of Contango and Crimson could adversely affect the combined company's future results.

The Merger involves the integration of two companies that have previously operated independently. The success of the Merger will depend, in large part, on the ability of the combined company to realize the anticipated benefits, including synergies, cost savings, innovation and operational efficiencies, from combining the businesses of Contango and Crimson. To realize these anticipated benefits, the businesses of Contango and Crimson must be successfully integrated. This integration will be complex and time-consuming. The failure to integrate successfully and to manage successfully the challenges presented by the integration process may result in the combined company not achieving the anticipated benefits of the Merger.

The future results of the combined company could suffer if the combined company does not effectively manage its expanded operations.

Following the Merger, the size of the business of the combined company increased significantly beyond the previous size of either Contango's or Crimson's business. The combined company's future success depends, in part, upon its ability to manage this expanded business, which could pose challenges for management, including challenges related to the management and monitoring of new operations and associated increased costs and complexity. There can be no assurances that the combined company will be successful or that it will realize the expected operating efficiencies, cost savings, revenue enhancements and other benefits currently anticipated from the Merger.

The combined company's debt may limit its financial flexibility.

Contango previously had no amounts outstanding under its credit facility and traditionally has carried minimal balances of long-term debt. Following the Merger, the combined company has more long-term debt. In addition, the combined company may incur additional debt from time to time in connection with the financing of operations, acquisitions, recapitalizations and

refinancing. The level of the combined company's debt could have several important effects on future operations, including, among others:

- If a portion of the combined company's cash is applied to the payment of principal or interest on the debt, less will be available for other purposes;
- Credit-rating agencies may change in the future with respect to the combined company, their ratings of that entity's debt and other obligations, which in turn impacts the costs, terms and conditions and availability of financing;
- Covenants contained in the combined company's existing and future debt arrangements will require the combined company to meet financial tests that may affect its flexibility in planning for and reacting to changes in its business, including possible acquisition opportunities;
- The combined company's ability to obtain additional financing for capital expenditures, acquisitions, general corporate and other purposes may be limited or burdened by increased costs or more restrictive covenants;
- The combined company may be at a competitive disadvantage to similar companies that have less debt;
- The combined company's vulnerability to adverse economic and industry conditions may increase; and
- The combined company may face limitations on its flexibility to plan for and react to changes in its business and the industries in which it operates.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

As of December 31, 2013, we operated all of our offshore wells, with an average working interest of 59%, and operated 55% of our onshore wells with an average working interest of 71%. As of December 31, 2013, our properties were located in the following regions: Offshore Gulf of Mexico, Southeast Texas, South Texas and Other. We intend to allocate a substantial portion of our drilling capital budget in 2014 to the development of the potential that we believe exists in our resource play position and offshore prospects, depending on commodity price environment, drilling and service costs, success rates, and capital availability.

Development, Exploration and Acquisition Expenditures

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Property acquisition costs:			
Unproved	$8,134	$19,982	$3,035
Proved	428,925	280	2,660
Exploration costs	15,551	41,265	7,622
Development costs	35,363	16,090	23,013
Total costs	$487,973	$77,617	$36,330

Included in proved property acquisition costs for the year ended December 31, 2013, is $413.9 million related to the acquisition of Crimson properties as a result of the Merger. Also included is $15 million related to exercising a preferential right and purchasing 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 $18.8 million. Preliminary estimated adjustments of approximately ($3.8 million) will reduce the purchase price to a total of $15 million, net to the Company. The purchase price adjustment is expected to be finalized in the first quarter of 2014.

Included in the exploration costs for the year ended December 31, 2013, is $10.6 million related to drilling our offshore South Timbalier 17 and Ship Shoal 255 wells.

The following table presents information regarding our share of the net costs incurred by Exaro in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Property acquisition costs	$—	$—	$—
Exploration costs	—	—	—
Development costs	51,014	20,528	—
Company's 37% share of costs incurred	$51,014	$20,528	$—

Property Dispositions

On December 31, 2013, the Company sold to an independent third party approximately 7.1% of its interest in all developed and undeveloped properties in Madison and Grimes Counties. The total sales price of $20 million is subject to a purchase price adjustment, based on production and operating expenses between the effective date of July 1, 2013 and the closing date of December 31, 2013. Preliminary estimated adjustments to the sales price of approximately $0.4 million will increase the total proceeds from sales of these properties to $20.4 million, and is expected to be finalized in the first quarter of 2014. Metrics for the sale were approximately $91,007 per flowing barrel of equivalent daily production and $47.32 per equivalent barrel of proved reserves. A gain of approximately $6.6 million related to this sale was recognized in the year ended December 31, 2013.

We had additional property dispositions during the years ended December 31, 2012 and 2011, which were all classified as discontinued operations for all periods presented. See Note 18 to our Financial Statements - "Discontinued Operations" for a detailed description of these dispositions.

Drilling Activity

As of December 31, 2013, we were drilling one offshore well, Ship Shoal 255, with drilling operations forecasted to conclude in March 2014. We were also drilling two onshore wells, one in the Woodbine area and one in the Buda area, whose results are not included below. The following table shows our exploratory and developmental drilling activity for the periods indicated. In the table, “gross” wells refer to wells in which we have a working interest, and “net” wells refer to gross wells multiplied by our working interest in such wells.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	3	0.3	—	—	—	—
Productive (offshore)	1	0.8	—	—	1	1.0
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	2	2.0	—	—
Total	4	1.1	2	2.0	1	1.0

Included in productive (onshore) wells for the year ended December 31, 2013 are three non-operated wells drilled in the TMS. Included in productive (offshore) wells for the year ended December 31, 2013 is the Company's South Timbalier 17 prospect we expect will begin production in mid-2014.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive (onshore)	5	3.2	—	—	1	0.3
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	5	3.2	—	—	1	0.3

Included in productive (onshore) wells for the year ended December 31, 2013 are five onshore wells drilled after October 1, 2013, the date of the Merger. For the fiscal year ended December 31, 2011, the one productive (onshore) well relates to the Rexer-Tusa #2, which was sold October 2011. The Rexer-Tusa #2 is classified as discontinued operations in our financial statements for all periods presented.

Exploration and Development Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of crude oil, natural gas and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres. The following table shows the approximate developed and undeveloped acreage that we have an interest in, by region, at December 31, 2013.

	Developed Acreage (1)(2)		Undeveloped Acreage (1)(3)	
	Gross (4)	Net (5)	Gross (4)	Net (5)
Offshore GOM	14,618	11,828	39,692	39,692
Southeast Texas	24,239	14,805	18,341	11,671
South Texas	85,771	44,329	19,593	11,556
Other (6)	17,229	9,180	52,281	36,911
Total	141,857	80,142	129,907	99,830

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.
(2) Developed acreage consists of acres spaced or assignable to productive wells.
(3) Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.
(4) Gross acres refer to the number of acres in which we own a working interest.
(5) Net acres represent the number of acres attributable to an owner's proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).
(6) Other includes acreage in Louisiana, Colorado, Mississippi and East Texas.

Included in the Offshore GOM acres in the table above are the beneficial interests we have in the offshore acreage owned by REX. The above table includes our 32.3% interest in REX's 625 net developed acres.

Our offshore Gulf of Mexico leases expire in 2017 and 2018. Our onshore leases will expire over the next three years as follows, unless we establish production or take action to extend the terms of our leases:

	Year ending December 31,					
	2014		2015		2016	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Southeast Texas	6,652	4,450	2,700	1,320	2,871	1,982
South Texas	2,698	547	—	—	5,039	2,833
Other	1,697	753	30,608	24,351	10,373	5,065
Total	11,047	5,750	33,308	25,671	18,283	9,880

Production, Price and Cost History

See "Part I, Item 7. -Management's Discussion and Analysis of Financial Condition and Results of Operations."

Productive Wells

Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a "productive" well. The following table sets forth the number of gross and net productive natural gas and oil wells in which we owned an interest as of December 31, 2013:

	Natural Gas Wells		Oil Wells	
	Gross Wells (1)	Net Wells (2)	Gross Wells (1)	Net Wells (2)
Offshore GOM	13	7.7	—	—
Southeast Texas	51	28.6	28	15.7
South Texas	244	130.7	30	14.1
Other	61	26.9	9	2.8
Total	369	193.9	67	32.6

(1) A gross well is a well in which we own an interest.
(2) The number of net wells is the sum of our fractional working interests owned in gross wells.

Natural Gas and Oil Reserves

Estimates of proved reserves and future net revenue as of December 31, 2013 were prepared by NSAI and Cobb, our independent petroleum engineering firms. Approximately 61% and 39% of the proved reserves estimates shown herein at December 31, 2013 have been independently prepared by Cobb and NSAI, respectively. Cobb prepared the proved reserves estimates as of December 31, 2013 for all of our offshore properties and NSAI prepared the proved reserves estimates as of December 31, 2013 for all of our onshore properties.

Estimates of proved reserves and future net revenue as of December 31, 2012 and 2011 were prepared by Cobb, all in accordance with the definitions and regulations of the SEC. The scope and results of their procedures are summarized in their reports, which are included as exhibits to this Form 10-K/A. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The estimates of proved reserves and future net revenue as of December 31, 2013 were reviewed by our corporate reservoir engineering department that is independent of the operations department. The corporate reservoir engineering department interacts with geoscience, operating, accounting, and marketing departments to review the integrity, accuracy and timeliness of the data, methods, and assumptions used in the preparation of the reserves estimates. All relevant data is compiled in a computer database application to which only authorized personnel are given access rights. Our Senior Vice President - Engineering is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for reviewing any reserves estimates prepared by an independent petroleum engineering firm. Our Senior Vice President - Engineering has a Bachelor of Science degree in Petroleum Engineering from the University of Texas and over 35 years of industry experience with positions of increasing responsibility. He reports directly to our President and Chief Executive Officer. Reserves are also reviewed internally with senior management and presented to our board of directors in summary form on a quarterly basis.

The estimates of proved reserves and future net revenues as of December 31, 2012 and 2011 were the responsibility of our management, and members of our management met regularly with our independent third-party engineers to review these reserve estimates. Mr. Joseph J. Romano, the Company's then-Chief Executive Officer, had primary responsibility for the preparation of the reserve report. Mr. Romano has been in the energy industry for over 35 years, but also relied on others with technical backgrounds in a collaborative effort, all of whom provided input to the independent third-party engineers. Mr. Brad Juneau, one of the Company's directors, monitored production and pressure data daily and provided the majority of the input. Mr. Juneau holds a BS degree in petroleum engineering from Louisiana State University. Mr. Juneau has over 30 years of experience in the oil and gas industry and was a former registered petroleum engineer in the State of Texas. Other executives in accounting and production have advanced degrees and specialty licenses and also provided input to the independent third-party engineers and assisted in reviewing the reports.

We maintain adequate and effective internal controls over the underlying data upon which reserves estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is communicated to our reservoir engineers quarterly, is confirmed when our third-party reservoir engineers hold technical meetings with geologists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in Internal Controls - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All data such as commodity prices, lease operating expenses, production taxes, field level commodity price differentials, ownership percentages, and well production data are updated in the reserve database by our third-party reservoir engineers and then analyzed by management to ensure that they have been entered accurately and that all updates are complete. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firms prepare their independent reserve estimates and final report.

The following table reflects our estimated proved reserves as of the dates indicated:

	December 31, 2013	2012	2011
Crude Oil and Condensate (MBbl) (1)			
Developed	5,223	2,514	3,539
Undeveloped	4,475	—	(46)
Total	9,698	2,514	3,493
Natural Gas (MMcf) (1)			
Developed	185,535	166,307	209,903
Undeveloped	22,395	7,725	2,920
Total	207,930	174,032	212,823
Natural Gas Liquids (MBbl) (1)			
Developed	6,453	5,103	4,343
Undeveloped	1,505	227	227
Total	7,958	5,330	4,570
Total MMcfe			
Developed	255,591	212,009	257,195
Undeveloped	58,275	9,087	4,006
Total	313,866	221,096	261,201
Proved developed reserves percentage	81 %	96 %	98 %
Prices utilized in estimates (2):			
Crude oil ($/Bbl)	$106.80	$114.24	$104.24
Natural gas ($/MMBtu)	$3.73	$2.85	$4.37
Natural gas liquids ($/Bbl)	$35.92	$58.39	$59.37

(1) Excludes reserves attributable to our 37% investment in Exaro.

(2) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices are adjusted for

quality, energy content, transportation fees and regional price differentials in determining proved reserves.

PV 10

PV-10 at year-end is a non-GAAP financial measure and represents the present value, discounted at 10% per year, of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure of Discounted Net Cash Flows represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV 10 (in thousands):

	December 31, 2013	2012
Pre-tax net present value, discounted at 10%	$987,213	$594,397
Future income taxes, discounted at 10%	(215,770)	(206,385)
Standardized measure of discounted future net cash flows	$771,443	$388,012

The following table reflects our estimated proved reserves by category as of December 31, 2013 (dollars in thousands):

	Crude Oil and Condensate (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV 10
Proved developed producing	4,342	128,738	4,531	181,976	58 %	$635,075
Proved developed non-producing	881	56,797	1,922	73,615	23 %	159,683
Proved undeveloped	4,475	22,395	1,505	58,275	19 %	192,455
Total	9,698	207,930	7,958	313,866	100 %	$987,213

Our estimated net proved reserves as of December 31, 2013, were approximately 19% crude oil and condensate, 66% natural gas and 15% natural gas liquids.

Proved Developed Reserves

Total proved developed reserves increased from 212.0 Bcfe at December 31, 2012 to 255.6 Bcfe at December 31, 2013 primarily as a result of our Merger with Crimson. Also contributing to the increase was the exercise of our preferential right to purchase approximately 17.0 Bcfe related to our five Contango-operated Dutch wells, slightly offset by 28.2 Bcfe of production, a 19.2 Bcfe decrease in our Dutch and Mary Rose reserve estimates based upon additional pressure data, and a 2.5 Bcfe decrease in our Vermilion 170 reserve estimates, as determined by our reservoir engineer.

Proved Undeveloped Reserves

The Company annually reviews any proved undeveloped reserves (“PUDs”) to ensure their development within five years from the date of originally booking the reserves. As of December 31, 2013, the Company had approximately 58.3 Bcfe of PUDs related to its onshore activities. Development costs related to these PUDs are projected to be approximately $162 million over the next five years, including $48.9 million estimated for expenditures in 2014. Our financial resources are expected to be sufficient and within our budget to drill all of the remaining 58.3 Bcfe of proved undeveloped reserves within the five year period.

The following table presents the changes in our total proved undeveloped reserves for the year ended December 31, 2013:

	Proved Undeveloped Reserves (Mmcfe)
Proved undeveloped reserves at December 31, 2012 (1)	9,087
Revisions of previous estimates (2)	(6,525)
Extensions, discoveries and other additions (3)	15,024

Purchase of minerals in place (4)	44,289
Disposition of reserves in place	(1,500)
Conversion to proved developed	(2,100)
Proved undeveloped reserves at December 31, 2013	58,275

(1) Attributable to a rate acceleration well in our Dutch and Mary Rose field. This well will be drilled in the main Cib Op reservoir. The acceleration benefits of drilling this well are an incremental net positive PV-10, but only a modest incremental volumetric reserves, because the main Cib Op reservoir is a depletion drive retrograde gas reservoir. Our reservoir engineer’s simulation model indicates that the timing of the pressure depletion, and the distribution of that depletion across the field, will have an effect on all of the wells in communication with this rate acceleration well. The reserves attributable to this rate acceleration well are calculated incrementally. The field-wide simulation model is run first without this well to generate a total field gas and condensate projection. The model is then run again with the rate acceleration well included. The difference between these two cases is the incremental PUD reserve case. Of the gas volumes the rate acceleration well is projected to produce, the majority comes from other wells in the field, such that the incremental gas recovery for the rate acceleration well is much less, and results in a negative condensate volume as of December 31, 2011.
(2) Of this amount, approximately 6.0 Bcfe is attributable to the rate acceleration well in our Dutch and Mary Rose field, as a result of additional information obtained from the other wells in that field.
(3) Of this amount, 2.2 Bcfe is attributable to our South Timbalier 17 well, which we expect to begin production in mid-2014, while the remaining 12.8 Bcfe is attributable to onshore drilling during the quarter ended December 31, 2013.
(4) Attributable to our Merger with Crimson and the purchase of additional interests in our operated Dutch wells.
Significant Properties

Summary proved reserve information for our properties as of December 31, 2013, by region, is provided below, excluding reserves attributable to our investment in Exaro (dollars in thousands):

Regions	Proved Reserves Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (Mmcfe)	PV 10[(1)]
Offshore GOM	2,032	150,495	4,643	190,545	$554,576
Southeast Texas	4,645	16,388	1,332	52,250	264,320
South Texas	2,661	36,382	1,820	63,268	150,386
Other	360	4,665	163	7,803	17,931
Total	9,698	207,930	7,958	313,866	$987,213

(1) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices, using SEC rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

While we are reasonably certain of recovering our calculated reserves, the process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third party engineers must project production rates, estimate timing and amount of development expenditures, analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of all of this data may vary. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.
Reserves Attributable to our Investment in Exaro

Estimates of proved reserves and future net revenue as of December 31, 2013 and 2012 associated with our investment in Exaro, which we account for using the equity method, were prepared by W.D. Von Gonten and Associates ("Von Gonten") in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Reserves as of December 31, 2013 were reviewed by our corporate reservoir engineering department as described above. Reserves as of December 31, 2012 were reviewed by members of the Company's management, including Mr. Joseph J. Romano, the Company's then-Chief Executive Officer, and Mr. Brad Juneau, as described above. The technical individual at Von Gonten responsible for overseeing the preparation of our reserve estimates as of December 31, 2013 and December 31, 2012 has over 13 years of practical experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas; holds a Bachelor of Science Degree in Petroleum Engineering; and is a member in good standing of the Society of Petroleum Engineers.

The following table reflects our estimated proved reserves attributable to our Investment in Exaro:

	December 31, 2013	December 31, 2012
Crude Oil (MBbl)		
Developed	439	133
Undeveloped	—	124
Total	439	257
Natural Gas (MMcf)		
Developed	39,068	11,056
Undeveloped	—	5,771
Total	39,068	16,827
Total MMcfe		
Developed	41,702	11,854
Undeveloped	—	6,515
Total	41,702	18,369
Proved developed reserves percentage	100 %	65 %
Standardized measure [1]	$ 63,906	$ 5,270
Prices utilized in estimates [2]		
Crude oil ($/Bbl)	$ 87.89	$ 85.71
Natural gas ($/MMBtu)	$ 4.04	$ 2.78

(1) The Company's share of the standardized measure of discounted future net cash flows attributable to our investment in Exaro does not include the effect of income taxes because Exaro is treated a partnership for tax purposes. Exaro allocates any income or expense for tax purposes to its partners.

(2) Under SEC rules, pri