CONTANGO OIL & GAS CO
Form 10-K
March 03, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

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

717 Texas Avenue, Suite 2900

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 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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 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.

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

Large accelerated filer	Accelerated filer	Non-accelerated filer (Do not check if smaller reporting company)	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

At June 30, 2014, 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 $618 million. As of February 27, 2015, there were 19,155,847 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.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2014

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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 operator of deep high pressure and high 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;

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- 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.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and natural gas liquids that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and natural gas liquids that are ultimately recovered.

All forward-looking statements, expressed or implied, in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or person acting on our behalf may issue.

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.

All references in this Form 10-K 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 relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves is based on estimates prepared by independent engineers, and is net to our interest.

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PART I

Item 1. Business

Overview

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

On October 1, 2013, we completed a merger with Crimson Exploration Inc. (“Crimson”), in an all-stock transaction pursuant to which Crimson became a wholly-owned subsidiary of Contango (the “Merger"). Accordingly, 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 20.3% of the post-Merger Contango. The Company has its headquarters and principal corporate office in Houston, Texas.

On October 1, 2013, our Board of Directors approved a change in fiscal year end from June 30 to December 31. On March 3, 2014, we filed a Transition Report on Form 10-KT which covered the transition period of July 1, 2013 through December 31, 2013, which included six months of Contango activity (July - December) and three months of post-Merger Crimson activity (October - December). Also, on March 28, 2014 we filed an Annual Report on Form 10-K/A to present the financial statements of the Company on a calendar year basis which included the twelve months ended December 31, 2013 and 2012. This Annual report on Form 10-K presents our information for the twelve-month periods ended December 31, 2014, 2013 and 2012. Unless otherwise noted, all references to "years" in this report refer to the twelve-month periods ended December 31 of each year.

We have historically focused our operations in the GOM, but our merger with Crimson has given us access to lower risk, long life, onshore resource plays. In 2014, our drilling activity focused primarily on the Woodbine oil and liquids-rich play in Madison and Grimes counties, Texas (our Southeast Texas Region), on the Buda Limestone oil and liquids-rich play in Zavala and Dimmit counties, Texas (our South Texas Region), in the Cretaceous Sands in Fayette and Gonzales counties, Texas (also in our South Texas Region) and the late 2014/early 2015 commencement of drilling in Wyoming where we are targeting the Mowry Shale and the Muddy Sandstone formations. We believe these areas provide long-term growth potential from multiple formations that we believe to be productive for oil and natural gas.

Additionally, we have (i) a 37% equity investment in Exaro Energy III LLC (“Exaro”) that is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; (ii) leasehold positions and minor 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 may also be prospective in the Niobrara Shale oil play; (v) operated producing properties in the Haynesville Shale, Mid Bossier and James Lime formations in East Texas; and (vi) six exploratory prospects in the shallow waters of the GOM.

Our production for the year ended December 31, 2014 was approximately 40.3 Bcfe (or 110.5 Mmcfed), was 61% from our offshore properties and was 64% natural gas. Our production for the three months ended December 31, 2014

was approximately 9.8 Bcfe (or 106.2 Mmcfed), was 64% from our offshore properties and was 68% natural gas. As of December 31, 2014, our proved reserves were approximately 76% proved developed, were 52% offshore, were 65% natural gas and were 96% attributed to wells and properties operated by us.

As of December 31, 2014, our proved reserves, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") and William M. Cobb and Associates ("Cobb"), our independent petroleum engineering firms for our onshore and offshore properties, respectively, in accordance with reserve reporting guidelines required by the Securities and Exchange Commission ("SEC"), were approximately 275.2 Bcfe, consisting of 179.7 Bcf of natural gas, 8.4 MMBbl of crude oil and condensate and 7.5 MMBbl of natural gas liquids ("NGLs"), with a present value, discounted at a 10% rate (PV 10), of $796.9 million, and a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $648.0 million. 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.

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The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2014 (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, 2014:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Offshore						
GOM	143.8	5 %	80 %	15 %	100 %	67.1
Southeast Texas	63.8	43 %	36 %	21 %	40 %	25.9
South Texas	54.8	23 %	60 %	17 %	53 %	14.5
Other (1)	12.8	31 %	63 %	6 %	33 %	3.0
Total	275.2					110.5

(1) East Texas, Mississippi, Louisiana, and Colorado

Our Strategy

Recently, our strategy has been to grow reserves and production by developing our existing property base, by utilizing our cash flow to drill selected high-potential Gulf of Mexico exploratory prospects, to exploit our lower-risk unproved oil and liquids resource potential in our onshore resource plays, and to pursue new onshore resource play opportunities organically, or through acquisition, that are complementary to our existing asset base. Due to the current low price environment, and the uncertainty for prices for the immediate future, our 2015 strategy will be to limit drilling to that which is necessary to fulfill commitments, preserve core acreage or test the geological viability of new plays or untested formations. Our priorities for 2015 will be to limit drilling until commodity prices improve and/or service costs decline, to preserve our healthy balance sheet by limiting capital expenditures to a level below cash flow, and to identify strategic opportunities for growth in this low price environment.

Specific key elements of our long-term business strategy have been:

- Enhance our portfolio by dedicating the majority of our drilling capital to our oil and liquids-rich opportunities. Due to the superior economics of oil production, as compared to natural gas, we have allocated the majority of our recent capital budget to oil and liquids-weighted opportunities as we strive to transition from a heavily weighted natural gas production profile to a more balanced reserve and production profile between oil/liquids and natural gas. Our long term strategy is to continue to develop the oil and natural gas liquids resource potential that we believe exists in numerous formations within our various oil/liquids weighted resource plays.
- 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, both undeveloped and developed, in areas where we currently have a presence and/or specific operating expertise, and pursue sizable undeveloped acreage positions, at reasonable cost, in new areas that we feel have significant exploration, exploitation or operational upside.

- Selectively exploit, under a higher commodity price environment, our existing onshore producing conventional natural gas property portfolio to generate additional cash flows. We believe our multi-year drilling inventory of exploitation opportunities on our existing onshore conventional natural gas oriented producing properties provides us with a solid, dependable platform for future reserve and production growth. We have 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 2015.

In 2014 specifically, we focused on our inventory of crude oil and liquids-rich projects with drilling programs in each of the Woodbine play in Madison and Grimes counties, Texas, the Buda play in Dimmit County, Texas and initiated drilling in our newly acquired acreage in the Fayette County, Texas, and Wyoming plays. We have developed a significant inventory of quality drilling opportunities on our existing property base that we believe should provide multiyear reserve growth.

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Our 2015 Strategy

As a result of the dramatic downturn in crude oil, natural gas and natural gas liquids prices in 2014 and early 2015, the negative impact of those price declines on the economics of most domestic resource plays, and the continuing uncertainty as to when, or how much, the commodity price environment might improve, our capital expenditure program for 2015 is expected to be focused on: (i) the preservation of our strong and flexible financial position, including limiting our overall capital expenditure budget to no more than internally generated cash flow; (ii) focusing drilling expenditures on strategic projects; (iii) identification of opportunities for cost efficiencies in all areas of our operations; and (iv) continuing to identify and, when appropriate, pursue new resource potential opportunities, internally and through acquisition. Our current capital budget for 2015 should allow us to meet our contractual requirements, remain in position to preserve our term acreage where we deem appropriate and maintain our already strong financial profile. We will continuously monitor the commodity price environment, stability and forecast, and if warranted, make adjustments to our investment strategy as the year progresses.

We believe that a continuing low commodity price environment could put pressure on over-leveraged or under-funded oil and natural gas exploration and production companies to consider asset sales or strategic combinations. Should a complementary and accretive opportunity materialize, our strong financial profile, cash flow and liquidity should position us to capitalize on such an opportunity. Accordingly, we plan to closely monitor the industry to identify and evaluate appropriate acquisition opportunities. Our acquisition efforts will typically be focused on areas in which we can leverage our geographic and geological expertise, and where we can develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves.

Properties

Offshore Gulf of Mexico

As of December 31, 2014, our offshore production consisted of seven federal and six State of Louisiana Company-operated wells in the shallow waters of the GOM. These 13 wells produce from four fields. The following summary table sets forth certain information with respect to our offshore reserves as of December 31, 2014 and average daily production for the year ended December 31, 2014:

Field	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Dutch and Mary Rose	128.0	5 %	80 %	15 %	100 %	56.4
Vermilion 170	14.1	2 %	82 %	16 %	100 %	7.5
Other Offshore	1.7	2 %	97 %	1 %	100 %	3.2
Total	143.8					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 lease for the Eugene Island 11 block, this does not impact our ability to operate our facilities located on that block. Operators in the GOM 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 our production platform we are able to access two separate markets which minimizes downtime risk and provides the ability for us to select the best sales price for our oil and natural gas production. Oil and natural gas production can flow via a TC Offshore (formerly ANR) pipeline to third-party owned and operated onshore processing facilities near Patterson, Louisiana. Alternatively, natural 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 onshore processing facility at Burns Point, Louisiana. Condensate can also flow via an ExxonMobil Pipeline Company pipeline to onshore markets and multiple refineries.

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We installed a turbine type compressor of sufficient capacity, based on normal production decline rates, to ultimately service all ten Dutch and Mary Rose wells at the Eugene Island 11 platform in July 2014. As of December 31, 2014, we had incurred approximately $11.7 million to design, build and install the compressor. We started central compression at the platform during the third quarter of 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 Company-operated Dutch wells from an independent oil and gas company for approximately $15 million, net after customary purchase price adjustments.

Vermilion 170 Field

We operate one well at Vermilion 170 which flows to a Company-owned and operated production platform at the same location. This platform services natural gas and condensate production, which flow via the Sea Robin Pipeline to a third-party owned and operated onshore processing plants. Based on production and decline rates, we designed, built and installed a compressor in 2013 at a cost of approximately $1.4 million. We anticipate commencing compression in late 2015 or early 2016.

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 in January, and the original tubing and casing were successfully removed. Operations were conducted to replace the tubing and restore the well, which resumed production in June 2013. During December 2014, our Vermillion 170 well production was shut-in for fourteen days due to issues with the Sea Robin Pipeline.

Other Offshore

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

On April 29, 2014, we reached total depth on our Ship Shoal 255 prospect in the GOM, and no commercial hydrocarbons were found. As a result, for the twelve months ended December 31, 2014, we recognized $31.5 million in exploration expense for the cost of drilling the well plus $15.6 million in impairment expense associated with $3.5 million of leasehold costs and $12.1 million related to a platform located in Block Ship Shoal 263 that was expected to be used by the Ship Shoal 255 well had it been successful.

On July 30, 2013, we spud our South Timbalier 17 prospect in state of Louisiana offshore waters, and on August 22, 2013 we announced completion of a successful well at a total measured depth of approximately 11,400 feet. After we completed the well and laid flowlines to a third-party owned facility, we commenced production in July 2014. Our net costs incurred to drill, complete and bring this well on production were $15.9 million as of December 31, 2014. We have a 75% working interest (53.3% net revenue interest) before payout, and a 59.3% working interest (42.1% net revenue interest) after payout. In December 2014, due to the low price environment, the net book value of our South Timbalier 17 exceeded the future undiscounted cash flows associated with its recoverable reserves, and we recognized an impairment expense of approximately $7.7 million during the year ended December 31, 2014.

During the year ended December 31, 2012, we spud our Ship Shoal 134 and South Timbalier 75 prospects, 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.

We currently hold six untested exploratory prospects on 15 offshore lease blocks. During the year ended December 31, 2014, we recognized full impairment related to the prospects which we do not currently intend to drill. We will pursue opportunities to realize future value from these leases through farmout, a sale or a possible trade for onshore opportunities.

Onshore Properties

Southeast Texas (Woodbine)

As of December 31, 2014, our Southeast Texas region included approximately 39,900 gross (23,000 net) acres, proven reserves of 63.8 Bcfe, and 91 gross (50.7 net) producing wells. Crimson has been active in this area since 2008, primarily focusing on

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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. During 2013, Crimson, and subsequently Contango, drilled 12 gross (8.0 net) wells on acreage targeting the Woodbine formation. During 2014, we drilled 18 gross (11.6 net) wells on acreage targeting the Woodbine formation. As of December 31, 2014, eight of these wells were producing, two were being evaluated and eight were in various stages of drilling or completion.

For 2015, our current budget includes completing the six wells initiated in late 2014 utilizing a pad drilling strategy on 500 foot spacing in the Chalktown area. When drilling from pads, several wells are drilled in succession, then completed in succession, and then put on production simultaneously to maximize recovery. Our 2015 budget also includes a single well in our Chalktown area that satisfies a farm-in commitment and a horizontal test of the previously untested Lower Lewisville formation in our Grimes County area. Should commodity prices improve and/or service costs decline meaningfully, we may increase our activity in this area. We currently have approximately 16,100 net acres in Madison and Grimes counties (approximately 50% of which is held by production), with a multi-year inventory of potential drilling locations, including the Woodbine, Eagle Ford Shale and Georgetown/Buda formations. As of December 31, 2014, we had 28 gross wells (17.9 net) producing in the Woodbine formation, including 20 gross wells (12.9 net) in the Force area, four gross wells (2.2 net) in the Iola/Grimes area and four gross wells (2.8 net) in the Chalktown area.

On December 31, 2013, we sold to an independent oil and gas company approximately 7.1% of our interest in all developed and undeveloped properties in Madison and Grimes Counties for approximately $20.4 million, or $91,007 per flowing barrel of equivalent daily production and $47.32 per equivalent barrel of proved reserves.

South Texas (Buda/Eagle Ford)

As of December 31, 2014, our South Texas region included approximately 165,800 gross (83,200 net) acres, proven reserves of 53.7 Bcfe, and 273 gross (143.4 net) producing wells. Of this, approximately 41,300 gross (21,400 net) acres are targeting the Buda and Eagle Ford Shale plays, approximately 70% 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 seven gross wells (3.3 net) in the Buda formation in Zavala and Dimmit counties. Six of the wells were successful, while one was a mechanical failure which was side tracked in 2014. During 2014, we drilled 14 gross wells (6.8 net) in the Buda formation in Zavala and Dimmit counties, all of which are currently producing. We drilled one additional well in Zavala and Dimmit counties during the fourth quarter of 2014 as a vertical pilot well to test the viability of the Eagle Ford and other formations in the area. We are evaluating the recovered cores before deciding on a development strategy for these areas. Our current capital program does not contemplate further drilling in Zavala and Dimmit counties in 2015 without improvement in the commodity price environment and/or service cost structure. Our estimated net proven Buda/Eagle Ford reserves in this area were 15.4 Bcfe, comprised of 76% liquids, with 26 gross (13.3 net) producing wells, as of December 31, 2014.

South Texas (Elm Hill Project)

As of December 31, 2014, we held approximately 55,900 gross acres (25,100 net) in Fayette, Gonzales, Caldwell and Bastrop counties, Texas. We believe that the current acreage position, if the play is successful, could add up to 200 gross drilling locations to our drilling inventory. During 2014, we drilled four gross wells (2.0 net) in this area, two of which commenced production during the fourth quarter of 2014, with the other two expected to commence production in early 2015. We currently plan to drill one more well during the first quarter of 2015 and then monitor area results before determining future plans for the area.

The remaining 68,600 gross (36,700 net) acres in our South Texas region are located in our conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved conventional reserves in this region were 38.3 Bcfe, comprised of 76% gas, with 245 gross (129.1 net) producing wells, as of December 31, 2014.

Natrona County, Wyoming (FRAMS Project)

In 2014, we acquired the right to earn approximately 119,300 gross acres (93,000 net acres with an 80% working interest) in Natrona County, Wyoming. During the fourth quarter of 2014, we sold a 20% working interest in this prospect to an independent oil and gas company, reducing our potential ownership to approximately 69,900 net acres with a 60% working interest. We spud our first well in this play during the fourth quarter of 2014 targeting the Mowry Shale, and expect to complete that well late in the first quarter

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or early second quarter of 2015. We will evaluate results from the first well for a number of months and determine future drilling plans for this area.

Weston County, Wyoming (N. Cheyenne Project)

In 2014, we acquired the right to earn approximately 49,000 gross acres (44,000 net acres with a 90% to 100% working interest) in Weston County, Wyoming. During the fourth quarter of 2014, we sold a 20% working interest in this prospect to an independent oil and gas company, reducing our potential ownership to approximately 35,000 net acres with a 72% to 80% working interest. We spud our first well in this play during the first quarter of 2015 targeting the Muddy Sandstone formation, and currently plan to complete that well early in the second quarter of 2015. We will evaluate results from the first well for a number of months and determine future drilling plans for this area. This acreage is approximately 125 miles to the northeast of our Natrona County acreage.

Other (East Texas)

As of December 31, 2014, our East Texas region included approximately 7,400 gross (4,300 net) acres primarily in San Augustine County, with proven reserves of 8.3 Bcfe comprised of 65% gas, and ten gross (5.1 net) producing wells. Crimson actively developed the dry gas Haynesville and Mid-Bossier Shales in this area in 2009 through 2011 during a more favorable natural gas price environment. During 2014, we drilled two gross (1.2 net) wells targeting the shallower, liquids-rich James Lime formation on our acreage in San Augustine County. We believe that the further exploitation of our acreage in the Haynesville, Mid-Bossier and James Lime formations will provide long-term natural gas reserve and production growth potential in the future; however, we do not anticipate devoting drilling capital to these formations until we see a sustained meaningful improvement in the natural gas price environment. As of December 31, 2014, approximately 69% of our acreage in our East Texas region is held by production.

Other (Colorado)

We hold approximately 16,100 gross (11,200 net) acres in the DJ Basin in Colorado (mostly in Adams and Weld counties). There has been sporadic 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 established 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 of this play is still uncertain due to the limited activity in the area and the current commodity price environment. Substantially all of our acreage in the DJ Basin is held by production. We plan to monitor the 2015 industry activity and results of our peers in the Niobrara Shale to determine our future strategy for maximizing the value of our position in the area.

Other (Tuscaloosa Marine Shale “TMS”)

We own a 25% non-operated working interest in the Crosby 12H-1 well in Wilkinson County, Mississippi, and an average non-operated working interest of less than 2.0% in three other wells in Mississippi, all targeting the TMS, an oil-focused shale play in central Louisiana and Mississippi. The Crosby 12H-1well is operated by Goodrich Petroleum Company LLC ("Goodrich”).

In addition, as of December 31, 2014, we have approximately 40,800 gross (29,000 net) undeveloped acres under lease 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 CMR Foster Creek 24-13H #1 well, where we own less than a 2% working interest. Due to the poor economics we have experienced in the area related to high drilling and completion costs and the current low oil price environment, we do not expect to drill TMS wells in the near future. Given the low likelihood that we will devote any capital to this area prior to lease expirations in 2015 and 2016, we recognized impairment of certain unproved properties in the third and fourth quarters of 2014. We plan to continue to evaluate participation in third-party operated wells with a small working interest as a means to obtain data from these wells to assist us in evaluating, and maximizing value, from our TMS acreage.

Other

As of December 31, 2014, we held approximately 3,300 gross (620 net) acres in small non-operated working interests in the Fenton field area of Calcasieu Parish, Louisiana and a minor operated crude oil property in Mississippi.

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Onshore Investments

Kaybob Duvernay – Alberta, Canada

In 2011, we invested 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, for approximately $30.5 million net to us. Of this amount, we have received $28.5 million, and we expect to receive the remaining $2.0 million within the next twelve months.

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 for a 37% ownership interest. As of December 31, 2014, we had invested approximately $46.9 million in Exaro. We account for Contaro's ownership in Exaro using the equity method of accounting, and therefore, do not include its share of individual operating results, reserves or production in those reported for our consolidated results.

As of December 31, 2014, Exaro had 625 wells on production over its 1,040 net acres, with a working interest between 14.4% and 32.5%. These wells were producing at a rate of approximately 41 Mmcfed, net to Exaro, plus an additional four wells that are either in the completion or fracture stimulation phase. The operator expects to have two drilling rigs running on this project during 2015. For the year ended December 31, 2014, the Company recognized a net investment gain of approximately $6.9 million, net of tax expense of $3.8 million, as a result of its investment in Exaro. As of December 31, 2014, reserves attributable to our investment in Exaro were 70.2 Bcfe. We do not anticipate making any additional equity contributions during 2015 as Exaro estimates that drilling capital will be funded through internally generated cash flow and borrowings under its revolving credit facility. See Note 11 to our Financial Statements - "Investment in Exaro Energy III LLC" for additional details related to this investment.

Outlook

As a result of the dramatic downturn in crude oil, natural gas and natural gas liquids pricing in late 2014 and early in 2015, the negative impact of those price declines on the economics of most domestic resource plays, and the continuing uncertainty as to when, or how much, the price environment might improve, our capital expenditure program for 2015 will be focused on: (i) the preservation of our strong and flexible financial position, including limiting our 2015 capital expenditure budget to no more than internally generated cash flow; (ii) focusing drilling expenditures on strategic projects; (iii) identification of opportunities for cost efficiencies in all areas of our operations; and (iv) continuing to identify new resource potential opportunities, internally and through acquisition. Our current capital budget for 2015 should allow us to meet our contractual requirements, remain in position to preserve our term acreage where appropriate and maintain our strong financial profile. We will continuously monitor the commodity price environment, stability and forecast, and if warranted, make adjustments to that strategy as the year progresses. Our capital expenditure budget is currently forecasted at approximately $50.6 million; a decrease of over 73% compared to our 2014 capital expenditures, and is expected to be funded from internally generated cash flow. Primary drilling activity is currently planned as follows:

- Woodbine – We forecast capital expenditures of approximately $21.3 million in Madison and Grimes counties to complete six gross wells (3.9 net) in our Chalktown area that we began drilling in 2014, and to drill an additional four gross wells (2.8 net).

- South Texas - We forecast capital expenditures of approximately $5.5 million in Fayette and Gonzales counties to complete a well that was in progress at year-end and to drill one additional gross well (0.5 net).
- Wyoming – We forecast capital expenditures of approximately $10.7 million to drill and complete two gross wells (1.4 net) in Natrona and Weston counties, targeting the Mowry Shale and Muddy Sandstone Formation, respectively.

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

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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.

Marketing and Pricing

We 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 typically utilize commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production, by using a series of swaps and costless collars. As of December 31, 2014, however, we had no commodity price hedges in place. Unrealized gains or losses 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, 2014, calculated on an equivalent basis, were ConocoPhillips Company (31%), Sunoco Inc. (27%), Shell Trading US Company (10%), Exxon Mobil Oil Corporation (7%), and Enterprise Products Operating LLC (5%). 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.

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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 federal, state and local governments; 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, state and local 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

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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.

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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 and state 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

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operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances released 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 December 2014, the EPA published a proposed rulemaking that it expects to finalize by October 1, 2015, which rulemaking proposes to revise the National Ambient Air Quality Standard for ozone between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards. Compliance with this or other regulatory initiatives could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines and significantly increasing our capital expenditures and operation costs, which could adversely impact our business.

Based on findings made by the EPA 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 GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant 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.

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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 to acquire and surrender emission allowances in return for emitting those GHGs. 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. For example, on January 14, 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. 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, a change in disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of salt water and ultimately increase the cost of our operations. For example, there exists a growing concern that the injection of saltwater and other fluids into belowground disposal wells triggers seismic activity in certain areas, including Texas, where we operate. In response to these concerns, in October 2014, the Texas Railroad Commission ("TRC") published a final rule governing

permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs..

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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. In December 2014, the Bureau of Ocean Energy Management (the "BOEM") issued a final rule, effective January 12, 2015, which raises OPA's damages liability cap from $75 million to $133.65 million. 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, or other similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing 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. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. 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 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 the first half of 2015. These ongoing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

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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 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 (the "FWS") 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. For example, in March 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. 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, time delays or limitations on our drilling program activities, which costs delays or limitation 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.

In response to the Deepwater Horizon drilling rig explosive incident and resulting oil spill in the United States Gulf of Mexico in 2010, the BOEM and the Bureau of Safety and Environmental Enforcement (the "BSEE"), each agencies of the U.S. Department of the Interior, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. These governmental agencies have implemented and enforced new rules, Notices to Lessees and Operators and temporary drilling moratoria that imposed safety and operational performance measures on exploration, development and production operators in the Gulf of Mexico or otherwise resulted in a temporary cessation of drilling activities. In addition, states may adopt and implement similar or more stringent legal requirements applicable to exploration and production activities in state waters. Compliance with these added and more stringent regulatory restrictions, in addition to any

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uncertainties or inconsistencies in current decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development and oil spill-response plans could adversely affect or delay new drilling and ongoing development efforts, which could have a material adverse impact on our business. Moreover, these governmental agencies are continuing to evaluate aspects of safety and operational performance in the Gulf of Mexico and, as a result, developing and implementing new, more restrictive requirements. One example is the 2013 amendments to the federal Workplace Safety Rule regarding the utilization of a more comprehensive safety and environmental management system ("SEMS"), which amended rule is sometimes referred to as SEMS II. A second, and more recent, example is the August 2014 Advanced Notice of Proposed Rulemaking that ultimately seeks to bolster the offshore financial assurance and bonding program. Among other adverse impacts, these additional measures could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding requirements and incurrence of associated added costs, limit operational activities in certain areas, or cause us to incur penalties, fines, or shut-in production. If material spill incidents similar to the Deepwater Horizon incident were to occur in the future, 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 laws and regulations regarding offshore oil and natural gas exploration and development, any of which developments could have a material adverse effect on our business.

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. However, in August 2014, BOEM published an Advance Notice of Proposed Rulemaking, pursuant to which it seeks to bolster its current bonding requirements for offshore oil and gas operations.

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.

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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 $75 million, 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 $35 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 support of the operating committee, we have contracted with J. Connor Consulting ("JCC") to coordinate the regulatory process relative to our offshore assets. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico. They provide preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills on behalf of oil and gas companies and pipeline operators.

Additionally, in support of our Gulf of Mexico operations, we have established a Regional Oil Spill Plan which has been approved by the BOEM. Our response team is trained annually and is tested through in-house spill drills. We have also contracted with O'Brien's Response Management ("O'Brien's"), who maintains an incident command center on 24 hour alert in Slidell, LA. In the event of an oil spill, the Company's response program is initiated by notifying O'Brien's any incident while the Company response team is mobilized to focus on source control and containment of the spill. O'Brien's would coordinate communications with state and federal agencies and would provide subject matter expertise in support of the response team.

We have also contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs in the event of a spill. CGA specializes in onsite control and cleanup and is on 24 hour alert with equipment currently stored at six bases along the gulf coast (Ingleside and Galveston, TX; Lake Charles, Houma, and Venice, LA; and Pascagoula, MS). CGA is opening new sites in Leeville, Morgan City and Harvey, LA. The CGA equipment stockpile is available to serve member oil spill response needs and includes open seas skimmers, and shoreline protection boom, communications equipment, dispersants with application systems, wildlife rehabilitation and a forward command center. CGA has retainers with aerial dispersant and mechanical recovery equipment contractors for spill response.

In addition to our membership in 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 and well control services.

We also have a full time health, safety and environmental professional who 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 identifies and mitigates safety and environmental hazards and the impacts of these hazards on design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company has established goals, performance measures, training and accountability for SEMS implementation. We also provide the necessary resources to maintain an effective SEMS and we review the adequacy and effectiveness of the SEMS program annually. Company facilities are 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 coordinate our SEMS program and to track compliance for production operations.

The BSEE enforces the SEMS requirements through regular audits. Failure of an audit may result in an Incident of Non-Compliance and could ultimately require a shut-in our Gulf of Mexico operations if not resolved within the required time.

Employees

On December 31, 2014, we had 92 full time employees, of which 23 were field personnel. 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

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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. 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, Executive Officers and Corporate Governance”, 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 office space for the year ended December 31, 2014 was approximately $2.1 million. We remain responsible for the rent at our previous corporate office at 3700 Buffalo Speedway in Houston, Texas, through February 29, 2016. 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. 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.

Available Information

You may read and copy all or any portion of this report on Form 10-K, 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, 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, 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

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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, domestic and global.
- 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. The Company has, in the past, utilized financial derivative contracts, such as swaps, costless collars and puts on commodity prices, to reduce exposure to potential declines in commodity prices. We currently do not have derivative arrangements in place on any post-2014 production.

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 South Texas and Wyoming resource plays, 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.

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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. Since the last regularly scheduled redetermination of our borrowing base, effective through May 1, 2015, commodity prices have continued to decline. The decline in prices will likely negatively impact the price decks utilized by banks in their calculation of the Company's borrowing base at May 1, 2015. It is not possible to forecast what that adjustment to the borrowing base might be at that time, and because of that uncertainty, the Company has currently limited its planned 2015 capital expenditure budget to a level that can be funded by internally generated cash flows. 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

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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,

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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 24% of our total estimated proved reserves at December 31, 2014 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, 2014 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2014. For our condensate and natural gas liquids, the average West Texas Intermediate (Cushing) posted price was $94.99 per barrel for offshore volumes and the average West Texas Intermediate (Plains) posted price was $91.48 per barrel for onshore volumes. For our natural gas, the average Henry Hub spot price was $4.30 per MMBtu for offshore volumes and the average Henry Hub spot price was $4.35 per MMBtu for onshore volumes. 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, 2014. If condensate and crude oil prices were $1.00 per Bbl lower than the prices used, our PV 10 as of December 31, 2014 would have decreased from $796.9 million to $790.0 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV 10 as of December 31, 2014, would have decreased from $796.9 million to $785.1 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. 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.

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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 unauthorized 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.

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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 of, 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 have, 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 typically 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. We currently do not have derivative arrangements in place on any post-2014 production.

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

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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 as they have done in late 2014 and early 2015, and stay low for the remainder of 2015, 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.

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

In response to findings that emissions of GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") and Title V permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. 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 to acquire and surrender emission allowances in return for emitting those GHGs. 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. For example, on January 14, 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. 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 unauthorized 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.

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- Reservoir damage.
- Severe damage to and destruction of property or equipment.
- Pollution and other environmental and natural resources 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.