CONTANGO OIL & GAS CO
Form 10-K
March 09, 2018
Table of Contents

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, 2017

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 American

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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

At June 30, 2017, 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 American, was $129.5 million. As of March 5, 2018, there were 25,479,438 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.

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

TABLE OF CONTENTS

Table of Contents

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin, integrate the operations relating thereto with our existing operations and realize the benefits associated therewith;
- our financial position;
- our business strategy, including outsourcing;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- volatility in natural gas, natural gas liquids and oil prices;
- 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;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations, and fund our drilling program;
- the cost and availability of rigs and other materials, services, 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;
- the need to take impairments on our properties due to lower commodity prices;
- the ability to post additional collateral for current bonds or comply with new supplemental bonding requirements imposed by the Bureau of Ocean Energy Management;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures, and other risks;

Table of Contents

- 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 retain key members of senior management and key technical employees and to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals (including additional taxes and changes in environmental regulations);
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements; and
- ability to obtain adequate 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 any 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 anc 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.

v

Table of Contents

PART I

Item 1. Business

Overview

We are a Houston, Texas based independent oil and natural gas company. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore properties in Texas and Wyoming and to use that cash flow to explore, develop, exploit, increase production from and acquire crude oil and natural gas properties in onshore West Texas, the Texas Gulf Coast and the Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of December 31, 2017:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Pecos County, Texas	Southern Delaware Basin (Wolfcamp)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Austin Chalk
Weston County, Wyoming	Muddy Sandstone
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC ("Exaro"). Production from this investment is not included in our reported production results or in our reported reserves for any periods reported herein.

Since October 2013, upon the merger with Crimson Exploration Inc. ("Crimson") (the "Merger"), and prior to the decline in crude oil and natural gas prices in 2015, we focused our drilling efforts on liquids-rich horizontal resource plays. Beginning in the second half of 2015, we reduced our drilling program in response to the challenging commodity price environment, and instead focused on: (i) the preservation of our strong and flexible financial position, including limiting our overall capital expenditure budget; (ii) the identification of opportunities for cost and production efficiencies in all areas of our operations; and (iii) the maintenance of core leases and the continued identification of new resource potential opportunities. As a result, until the latter half of 2016, our only drilling activity was in Weston County, Wyoming, where we completed our third well targeting the Muddy Sandstone formation. During the third quarter of 2016, we acquired a 12,100 gross acre position (5,000 net) in the Southern Delaware Basin in Pecos County, Texas (the "Acquisition"), and as of December 31, 2017, had increased our acreage in the Southern Delaware Basin to 16,500 gross acres (6,800 net). Since the Acquisition, we have begun production from seven wells in the Southern Delaware Basin and are waiting on completion of an eighth well. We currently expect that the Southern Delaware Basin position will continue to be the primary focus of our drilling program for 2018.

In addition to our above producing properties, we also have (i) operated producing properties in the Haynesville Shale, Mid Bossier Shale and the James Lime formations in East Texas and (ii) operated conventional producing properties in the south and southeast areas of Texas. In December 2016, we sold our operated producing properties in the Denver Julesburg Basin (“DJ Basin”) in Weld and Adams counties in Colorado.

During the quarter ended September 30, 2016, in conjunction with the Acquisition, we completed an underwritten public offering of 5,360,000 shares of our common stock for net proceeds of approximately $50.5 million, which were used to fund the initial purchase of this acreage and provide funding for the costs associated with drilling our initial wells in the Southern Delaware Basin.

Our production for the year ended December 31, 2017 was approximately 20.1 Bcfe (or 55.1 Mmcfe/d), was 68% from our offshore properties and was 69% natural gas. Our production for the three months ended December 31, 2017 was approximately 4.8 Bcfe (or 51.8 Mmcfe/d), was 66% from our offshore properties and was 68% natural gas. As of December 31, 2017, our proved reserves were approximately 65% proved developed, were 40% offshore, were 48% natural gas and were 98% attributed to wells and properties operated by us.

Table of Contents

As of December 31, 2017, our proved reserves, as estimated by Netherland, Sewell & Associates, Inc. (“NSAI”) and William M. Cobb and Associates (“Cobb”), our independent petroleum engineering firms, in accordance with reserve reporting guidelines required by the Securities and Exchange Commission (“SEC”), were approximately 189.3 Bcfe, consisting of 91.7 Bcf of natural gas, 10.6 MMBbl of crude oil and condensate and 5.6 MMBbl of natural gas liquids (“NGLs”), with a present value, discounted at a 10% rate (PV 10), of $257.3 million, and a Standardized Measure of Discounted Future Net Cash Flows (“Standardized Measure”) of $255.9 million. PV-10 as of December 31, 2017 was based on adjusted prices of $2.92 per MMbtu of natural gas, $47.41 per barrel of oil, and $18.59 per barrel of NGLs. PV-10 is not an accounting principle generally accepted in the United States of America (“GAAP”) and is therefore classified as a non-GAAP financial measure. A reconciliation of our Standardized Measure to PV 10 is provided under “Item 2. Properties PV-10”.

The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2017 (excluding 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, 2017:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate		Natural % Gas		% Natural Gas Liquids		% Proved Developed		Average Daily Production (Mmcfe/d)
Offshore GOM	75.4	3	%	82	%	15	%	100	%	37.7
Southeast Texas	30.9	41	%	37	%	22	%	63	%	8.0
South Texas	25.7	46	%	40	%	14	%	64	%	5.6
West Texas	55.5	64	%	15	%	21	%	19	%	2.6
Other (1)	1.8	65	%	32	%	3	%	100	%	1.2
Total	189.3									55.1

(1) Includes East Texas, Mississippi, Louisiana and Wyoming.

The following summary table sets forth certain information with respect to the proved reserves attributable to our investment in Exaro, as of December 31, 2017, as estimated by W.D. Von Gonten and Associates (“Von Gonten”), and our net share of Exaro’s average daily production for the year ended December 31, 2017:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate		% Natural Gas		% Natural Gas Liquids		% Proved Developed		Average Daily Production (Mmcfe/d)
Investment in Exaro	30.7	6	%	94	%	—	%	99	%	26.4

Our Strategy

Our long-term business strategy is:

• Enhancing our portfolio by dedicating the majority of our drilling capital to our oil and liquids-rich opportunities. A key element of 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, and where possible, to expand our presence in those plays. Due to the current superior economics of oil production, as compared to natural gas, we expect to focus on 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.

For the foreseeable future, we will focus our drilling capital on the Southern Delaware Basin position, as we believe it provides excellent returns in the current oil price environment. We believe we possess the flexibility to focus on the development of our Southern Delaware Basin potential without jeopardizing our acreage position in other areas, as the vast majority of our acreage in those other areas is held by production or has longer term lease terms.

- Pursuing accretive, opportunistic acquisitions that meet our strategic and financial objectives. We intend to evaluate 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 to pursue undeveloped acreage positions, at reasonable cost, in new areas that we believe to be complementary to our existing plays and feel have significant exploration, exploitation or operational upside. We believe that the ongoing low commodity price environment might provide growth opportunities for us through potential corporate combinations.

- Selectively exploiting, in 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

Table of Contents

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 will continuously monitor the commodity price environment and technical advancements, and if warranted, make adjustments to our investment strategy.

We currently expect to focus our 2018 capital program on our Southern Delaware Basin acreage, which is expected to continue to generate positive returns on our drilling investment in the current price environment. Assuming results are as expected, and market conditions remain favorable, we will proceed to drill throughout the year. Until a sustained improvement in commodity prices occurs, we do not currently expect to devote meaningful capital to our other areas, but will devote capital to those areas to fulfill leasehold commitments, preserve core acreage and, where determined appropriate to do so, expand our presence in those existing areas. We will continue to make balance sheet strength a priority in 2018 by limiting capital expenditures to a level that can be funded through internally generated cash flow and non-core asset sales. We will continue to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed acquisition opportunities that may arise in this low price environment. We retain the flexibility to be more aggressive in our drilling plans should planned results exceed expectations, should commodity prices continue to improve, and/or we continue to show progress in reducing our drilling and completion costs, thereby making an expansion of our drilling program an appropriate business decision. Our 2018 capital expenditure budget is initially expected to include the following:

- Pecos County, Texas – We forecast capital expenditures of approximately $52 million for drilling in this area.
- Other – We forecast capital expenditures of approximately $2 million for unproved leasehold acquisition costs.

Properties

Offshore Gulf of Mexico

As of December 31, 2017, our offshore assets consisted of six federal and five state of Louisiana company-operated wells in the shallow waters of the GOM. These 11 wells are located in two fields. The following summary table sets forth certain information with respect to our offshore reserves as of December 31, 2017 and average daily offshore production for the year ended December 31, 2017:

Field	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate		% Natural Gas		% Natural Gas Liquids		% Proved Developed		Average Daily Production (Mmcfe/d)
Dutch and Mary Rose	72.0	3	%	81	%	16	%	100	%	33.7
Vermilion 170	3.4	4	%	84	%	12	%	100	%	3.8
South Timbalier 17	—	—	%	—	%	—	%	—	%	0.2
Total	75.4									37.7

Dutch and Mary Rose Field

We operate five wells located in federal waters at Eugene Island 10 (“Dutch”), and five wells located in adjacent Louisiana state waters (“Mary Rose”). All Dutch and Mary Rose wells flow 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 gas markets thereby minimizing downtime risk and providing the ability to select the best sales price for our natural gas production. Oil and natural gas production can flow through our 20” gas pipeline to third-party owned and operated onshore processing facilities near Patterson, Louisiana. Alternatively, natural gas can flow via our 8” pipeline to a third-party owned and operated onshore processing facility at Burns Point, Louisiana. We have recently completed a 6” oil pipeline to third-party owned and operated onshore processing facilities in St. Mary Parish, Louisiana, providing us with two separate oil markets. Production facilities include a turbine type compressor capable of servicing all ten Dutch and Mary Rose wells at the Eugene Island 11 platform. Condensate can also flow to onshore markets and multiple refineries.

Table of Contents

Vermilion 170 Field

We own and operate one well located in federal waters with a dedicated production facility at Vermilion 170. Production from this platform, which includes compression equipment, flows via the Sea Robin Pipeline to a third-party owned and operated onshore processing plant.

Other Offshore

Our Ship Shoal 263 field, located in federal waters, and South Timbalier 17 field, located in Louisiana state waters, were historically included in “Other Offshore”. During 2017, the Ship Shoal field was permanently plugged and abandoned, and the production facilities were removed and sold. In late 2017, the South Timbalier well was permanently plugged and abandoned, and the production facilities were removed.

Onshore Properties

Southern Delaware Basin

Since the closing of the Acquisition in late July 2016, we and our partner have increased our leasehold footprint to approximately 6,800 acres, net to Contango. As of December 31, 2017, we currently estimate that we have proven reserves of 55.5 Bcfe and close to 400 gross drilling locations, initially targeting the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. Substantially all of the locations can accommodate 10,000 foot laterals. As previously disclosed, during 2017 we brought our first four Southern Delaware Basin wells on production (two in the Upper Wolfcamp A, one in the Middle Wolfcamp A, and one in the Lower Wolfcamp A), with an average maximum 30 day initial production rate (“IP”) of 968 Boed (72% oil).

In mid-December 2017, we brought our fifth horizontal well on production, the Crusader #1H, targeting the Lower Wolfcamp A. This well was drilled to a total measured depth (“TMD”) of 20,275 feet, including a 10,184 foot lateral, and was completed with 50 stages of fracture stimulation, reaching a 30-day average IP of 389 Boed (67% oil). Our sixth well, the Ragin Bull #3H, targeting the Lower Wolfcamp A, was spud in November 2017. This well was drilled to a TMD of 20,570 feet, including a 10,325 foot lateral, and was completed with 50 stages of fracture stimulation. Production began in January 2018, and the well reached a 30-day average IP of 716 Boed (67% oil).

Our seventh well, the River Rattler #1H, our first Wolfcamp B test, was spud in December 2017. This well was drilled to a TMD of 20,710 feet, including a 10,275 foot lateral, and was completed with 50 stages of fracture stimulation. Production is expected to begin in mid-March 2018. We continue to identify cost efficiencies in our drilling efforts, as evidenced by the fact that the Ragin Bull #3H and River Rattler #1H have been our most efficient wells to date, taking only 27 days from spud to TMD.

Our eighth well, the Ragin Bull #2H, our second Wolfcamp B test, was spud in January 2018. This well was drilled to a TMD of 20,624 feet, including a 10,344 foot lateral, and is currently waiting on completion with 50 stages of fracture stimulation. There have been multiple Wolfcamp B wells adjacent to our leasehold that have been put on production recently by our offset operators, thereby derisking the Wolfcamp B in the area and providing encouragement for the development of that formation on our acreage.

Southeast Texas (Woodbine)

As of December 31, 2017, our Southeast Texas region included approximately 29,300 gross (17,100 net) acres, proven reserves of 30.9 Bcfe, and 81 gross (45 net) producing wells. No drilling capital was allocated to this area in 2016 or 2017 due to the low commodity price environment. For 2018, our current budget does not anticipate further drilling in this area, but should we experience sustained improvement in commodity prices, we could increase our activity. We currently have approximately 12,100 net acres in Madison and Grimes counties, with a multi-year inventory of potential drilling locations encompassing the Woodbine, Eagle Ford Shale and/or Georgetown/Buda formations.

South Texas (Buda/Eagle Ford)

As of December 31, 2017, our South Texas region included approximately 89,600 gross (40,800 net) acres, proven reserves of 25.7 Bcfe, and 217 gross (96.5 net) producing wells. We believe approximately 16,700 gross (7,800 net) acres to be prospective for the Buda and Eagle Ford Shale plays. No drilling activity has been conducted in

Table of Contents

this area since 2014 due to the reduction in our capital expenditure programs in response to the commodity price environment. We do not anticipate devoting any drilling capital to this area in 2018.

Our estimated net proven Buda/Eagle Ford reserves in this area were 12.2 Bcfe, comprised of 94% liquids, with 41 gross (17.6 net) producing wells, as of December 31, 2017.

South Texas (Elm Hill Project)

As of December 31, 2017, we held approximately 4,900 gross acres (2,700 net) in Fayette, Gonzales, Caldwell and Bastrop counties, Texas. There was no drilling activity in 2016 or 2017, and we recognized an impairment expense of $6.8 million for the year ended December 31, 2016. The Company and its partner have no plans to further test this area.

The remaining 68,000 gross (30,300 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 12.1 Bcfe, comprised of 71% gas, with 176 gross (78.9 net) producing wells, as of December 31, 2017.

Weston County, Wyoming (N. Cheyenne Project)

In 2015, we began drilling the first of three successful wells in this area targeting the Muddy Sandstone formation. Based on current results, a sustained improvement in oil prices will be needed to justify allocation of drilling capital to this area compared to our Southern Delaware Basin position. As a result of drilling these wells, we have satisfied the right to earn 35,000 net acres (approximately 4% of which is held by production).

Natrona County, Wyoming (FRAMS Project)

We spud our first well targeting the Mowry Shale in 2015, which proved to be unsuccessful. As a result, we recognized $6.7 million in exploration expenses for the cost of drilling the well for the year ended December 31, 2016 and $2.9 million in impairment expense in 2016 related to our unproved acreage in Natrona County, Wyoming. No drilling activity was conducted in this area in 2017.

Other (East Texas)

As of December 31, 2017, our East Texas region included approximately 6,000 gross (3,600 net) acres primarily in San Augustine County, with proven reserves of 0.5 Bcfe comprised of 90% gas, and 10 gross (5.1 net) producing wells. We believe that the further exploitation of our acreage in the Haynesville, Mid-Bossier and James Lime formations may provide long-term natural gas reserve and production growth potential in the future. There has been renewed interest in this area by offset operators as they experiment with new frac techniques and refracing of previously drilled wells. We will continue to monitor that activity and results; however, we do not anticipate devoting any capital to this area during 2018. As of December 31, 2017, substantially all of our acreage in our East Texas region was held by production.

Other (Colorado)

On December 30, 2016, we completed the sale of all of our Colorado assets to an independent oil and gas company for an aggregate purchase price of $5.0 million, subject to normal post-closing adjustments. The properties sold consisted of approximately 16,000 gross (11,200 net) acres and associated producing vertical wells primarily in Adams and Weld counties. At the time of sale, the sold properties had proved reserves of 4.2 Bcfe and during 2016 average net daily production was 0.4 Mmcfe/d.

Other

As of December 31, 2017, we held approximately 8,300 gross (6,000 net) mostly undeveloped acres in Louisiana, Mississippi, and North Texas.

Impairment of Long-Lived Assets

We recognized approximately $1.8 million in non-cash impairment charges in 2017. Under US GAAP, an impairment charge is required when the unamortized capital cost of any individual property within the Company's

Table of Contents

proved property base exceeds the risked estimated future net cash flows from the proved, probable and possible reserves for that property. Included in the impairment charge for the year is approximately $0.3 million related to proved property impairment for our Tuscaloosa Marine Shale (“TMS”) properties, a shale play in central Louisiana and Mississippi, due to revised estimated reserves. The 2017 impairment charges also consist of $1.5 million related to the partial impairment of two unused offshore platforms in onshore storage.

If oil and/or natural gas prices decline from prices at December 31, 2017, we may be required to record additional non-cash impairment in the future, thereby impacting our financial results for that period.

Onshore Investments

Jonah Field – Sublette County, Wyoming

Our wholly-owned subsidiary, Contaro Company (“Contaro”), owns a 37% ownership interest in Exaro. As of December 31, 2017, we had invested approximately $46.9 million in Exaro, with no anticipation of making any additional equity contributions, as our commitment to invest in Exaro expired on March 31, 2017. 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, 2017, Exaro had 645 wells on production over its 5,760 gross acres (1,040 net acres), with a working interest between 2.4% and 32.5%. These wells were producing at a rate of approximately 26 Mmcfe/d, net to Exaro. The operator of these interests has applied for multiple drilling permits for horizontal wells that will be located on parts of our acreage. Exaro’s working interest in the drilling spacing units for the applied for horizontal wells ranges from 1% to 6%. As of December 31, 2017, the operator has been approved to drill two horizontal wells, in which Exaro has a net working interest of 2.4%. For the year ended December 31, 2017, the Company recognized a net investment gain of approximately $2.7 million, net of no tax expense, as a result of its investment in Exaro. As of December 31, 2017, reserves attributable to our investment in Exaro were 30.7 Bcfe. See Note 10 to our Financial Statements - “Investment in Exaro Energy III LLC” for additional details related to this investment.

Title to Properties

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

We have granted mortgage liens on substantially all of our natural gas and crude oil properties to secure our senior secured revolving credit facility. These mortgages and the related credit agreement contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 12 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/or costless collars. Unrealized gains or losses associated with hedges 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 being hedged.

Table of Contents

As of December 31, 2017, we had the following derivative contracts in place with members of our bank group:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	Jan 2018 - July 2018	Swap	370,000 MMBtus	$ 3.07 (1)
Natural Gas	Aug 2018 - Oct 2018	Swap	70,000 MMBtus	$ 3.07 (1)
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$ 3.07 (1)
Oil	Jan 2018 - June 2018	Swap	20,000 Bbls	$ 56.40 (2)
Oil	July 2018 - Oct 2018	Collar	20,000 Bbls	$ 52.00 - 56.85 (2)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$ 52.00 - 56.85 (2)
Oil	Jan 2018 - Dec 2018	Collar	2,000 Bbls	$ 52.00 - 58.76 (3)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)

In January 2018, we entered into the following additional derivative contracts with members of our bank group:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Oil	Jan 2018 - July 2018	Collar	6,000 Bbls	$ 58.00 - 68.00 (2)
Oil	Nov 2018 - Dec 2018	Collar	5,000 Bbls	$ 58.00 - 68.00 (2)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$ 52.00 - 59.45 (3)

(1) Based on Henry Hub NYMEX natural gas prices.
(2) Based on Argus Louisiana Light Sweet crude oil prices.
(3) Based on West Texas Intermediate crude oil prices.

Decreases in commodity prices 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.

Table of Contents

Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. The largest purchaser of our production for the year ended December 31, 2017, calculated on an equivalent basis, was ConocoPhillips Company (51.2%). This concentration 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.

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

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. 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

Table of Contents

areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws, which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of crude oil, natural gas and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

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

Section 1(b) of the NGA exempts gas gathering facilities from the FERC's jurisdiction. We believe that the gas gathering facilities we own meet the traditional tests the FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. While we own some gas gathering facilities, we also depend on gathering facilities owned and operated by third parties to gather production from our properties, and therefore, we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services, we also may be affected by these changes. Accordingly, we do not anticipate that we would be affected any differently than similarly situated gas producers.

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. FERC holds substantial enforcement authority, including the ability to potentially assess maximum civil penalties of approximately $1.24 million per day per violation, subject to annual adjustment for inflation. CFTC also holds substantial enforcement authority, including the ability to potentially assess maximum civil penalties of up to approximately $1.12 million per day per violation or triple the monetary gain.

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.

Table of Contents

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

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the natural gas 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. 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 potentially assess maximum civil penalties of approximately $1.18 million per day per violation, subject to annual adjustment for inflation. 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.

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. We do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of petroleum with which we compete.

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, which may cause us to incur significant capital expenditures or costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative,

Table of Contents

civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects 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 in environmental legislation and regulations in recent years has been to place more restrictions and limitations on activities that may affect the environment, which is expected to result in increased costs of doing business and consequently affect profitability.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund Law", and similar state laws, impose strict joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the current or past owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to 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, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we can provide no assurance that this exemption will be preserved in the future. For example, following in response to the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the U.S. District Court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any removal of this exclusion 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.

The Clean Air Act, as amended (the "CAA"), and comparable state laws 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.

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, impose permit reviews and restrict emissions of GHGs from certain large stationary sources. These EPA regulations could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. 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, including certain onshore and offshore production facilities, which include the majority of our operations. We are monitoring and reporting on GHG emissions from 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. Moreover, in December 2015, the United States joined other countries of the United Nations in preparing an agreement requiring member countries to review and establish goals for limiting GHG emissions. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions but, rather, includes pledges to voluntarily limit or reduce future emissions. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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 international, federal or state 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.

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 an issued permit. 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 (the "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. Furthermore, in response to a growing concern that the injection of produced water and other fluids into belowground disposal wells triggers seismic activity in certain areas, some states, including Texas, where we operate, have imposed, and other states are considering imposing, additional requirements in the permitting or operation of produced water injection wells. In Texas, the Texas Railroad Commission ("TRC") has adopted a final rule governing the permitting or re-permitting of disposal wells that requires, 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. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and natural gas activities utilizing injection wells for produced water disposal. These existing and any new seismic requirements applicable to disposal wells that impose more stringent permitting or operational requirements could result in added costs to comply or, perhaps, may require alternative methods of disposing of produced water and other fluids, which could delay production schedules and also result in increased costs.

The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA applies to vessels, onshore facilities and offshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities and lessees and permittees of offshore leases may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. In addition, in January 2018, the federal Bureau of Ocean Energy Management ("BOEM") has raised OPA's damages liability cap to $137.7 million. OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill, and to prepare and submit for approval oil spill response plans. These oil spill response plans must detail the action to be taken in the event of a spill; identify contracted spill response equipment, materials, and trained personnel; and identify the time necessary to deploy these resources in the event of a spill. In addition, OPA currently requires a minimum financial responsibility demonstration of between $35 million and $150 million for companies operating on the federal Outer Continental Shelf ("OCS") waters, including the Gulf of Mexico. We are currently required to demonstrate, on an annual basis, that we have ready access to $35 million that can be used to respond to an oil spill from our facilities on the OCS. 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.

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 or other proppant 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 natural gas commissions, or other similar state agencies, but several federal agencies have also asserted regulatory authority over, or conducted investigations that focus upon, certain aspects of the process, including a suite of proposed rulemakings and final rules issued by the EPA and the federal Bureau of Land Management (the "BLM"), which legal requirements, to the extent finalized and implemented by the agencies, may impose more stringent requirements relating to the composition of fracturing fluids, emissions and discharges from hydraulic fracturing, chemical disclosures, and performances of fracturing activities on federal and Indian lands. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water under certain circumstances.

Congress has from time to time considered, but not enacted, legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process while, at the state level, several states, including Texas and Wyoming, 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 high volume hydraulic fracturing altogether, following the approach taken by the State of New York. 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. 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.

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. Governmental permits or authorizations that are subject to the requirements of NEPA are required for exploration and development projects on federal and Indian lands. 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

Table of Contents

species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. 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 one or more settlements entered into by the U.S. Fish and Wildlife Service (the “FWS”), the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA by specified timelines. 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, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the U.S. Occupational Safety and Health Administration 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.

In recent years, the BOEM and the BSEE, each agencies of the U.S. Department of the Interior, have imposed more stringent permitting procedures and regulatory safety and performance requirements for wells in federal waters. 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 more stringent regulatory restrictions, together with any uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts. In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions or obligations with respect to oil and natural gas exploration and production operations conducted offshore. Any new rules, regulations or legal initiatives 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 limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities. If the BOEM determines that increased financial assurance is required in connection with our offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled. For example, in April 2016, the BOEM published a proposed rule that would update existing air-emissions requirements relating to offshore oil and natural gas activity on the OCS. Additionally, the BOEM issued a Notice to Lessees and Operators (the “NTL #2016-N01”) that became effective in September 2016 and bolsters supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines and other facilities. Also, if material spill incidents were to occur, 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. Any one or more of the offshore-related matters described above could have a material adverse effect on our business, financial condition and results of operations.

These regulatory actions, or any new rules, regulations or legal initiatives 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 and costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases. Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material. If the BOEM determines that increased financial assurance is required in connection with our or any previously assigned offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled.

Table of Contents

During 2017, however, with the issuance of Order 3350 in May 2017 by U.S. Department of the Interior Secretary Ryan Zinke that directed the BOEM and the BSEE to reconsider a number of regulatory initiatives governing oil and natural gas exploration, development and production activities on the OCS ("Order 3350"), the BSEE and the BOEM have been directed to reconsider a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities, including, for example, NTL #2016-N01 and the rules relating to blow-out preventers and well control, and provide recommendations on whether such regulatory initiatives should continue to be implemented. Moreover, Order 3350 directed the BOEM to immediately cease all activities to promulgate the April 2016 proposed rule relating to offshore air quality control. One consequence of this review is that on December 29, 2017, the BSEE published proposed revisions to its regulations regarding offshore drilling safety equipment, which proposal includes the removal of the requirement for offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) is operational and functioning as designed in the most extreme conditions. The December 2017 proposed rule has not been finalized, and there remains substantial uncertainty as to the scope and extent of any revisions to existing oil and gas safety and performance-related regulations and other regulatory initiatives that ultimately will be adopted by the BSEE and the BOEM pursuant to those agencies' review process.

See "Item 1A. Risk Factors" for further discussion on hydraulic fracturing; ozone standards; climate change, including methane or other greenhouse gas emissions; releases of regulated substances; and other aspects of compliance with legal or financial assurance requirements or relating to environmental protection, including with respect to offshore leases.

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.

Whereas the BLM administers oil and natural gas leases held by the Company on federal onshore lands, the BOEM administers the natural gas and oil leases held by the Company on federal onshore lands and offshore tracts in the OCS. The Office of Natural Resources Revenue (the "ONRR") collects 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 ONRR 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.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells, decommission or remove platforms and pipelines, and clear the seafloor of obstructions at the end of production (collectively, "decommissioning obligations"), the BOEM generally requires that lessees post supplemental bonds or other acceptable financial assurances that such obligations will be met. Historically, our financial assurance costs to satisfy decommissioning obligations have not had a material adverse effect on our results of operations; however, the BOEM continues to consider imposing more stringent financial assurance requirements on offshore operators on the OCS. For example, the BOEM issued NTL #2016-N01 that went into effect in September 2016 and augments requirements for the posting of additional financial assurance by offshore lessees, among others, to assure that sufficient funds are available to satisfy decommissioning obligations on the OCS. If the BOEM determines under this new NTL that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. While we do not meet the requirements for self-insurance, we estimated the impact of the requirement to provide additional security under NTL #2016-N01 for our operations in the Gulf of Mexico and do not believe that the revised policy will have a material impact on our operations in the Gulf of Mexico.

During 2017, however, with the issuance of Order 3350, the BSEE and the BOEM have been directed to reconsider a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities, including, for example, NTL #2016-N01. Consequently, during 2017, the BOEM extended the start date for implementing NTL #2016-N01 indefinitely beyond June 30, 2017. This extension currently remains in effect; however,

Table of Contents

the BOEM reserved the right to re-issue sole liability orders in the future, including in the event that it determines there is a substantial risk of nonperformance of the interest holder's decommissioning sole liabilities. Following completion of its review, the BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the review is completed and the BOEM determines what additional financial assurance may be required by us, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties. In the event that we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require certain of our operations on federal leases to be suspended or cancelled or otherwise impose monetary penalties.

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.

Health, Safety and Environmental Program

Our Health, Safety and Environmental ("HS&E") Program is supervised by an operating committee of senior management to ensure 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 Response Plan which has been approved by the BSEE. 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 Houston, TX. In the event of an oil spill, the Company's response program is initiated by notifying O'Brien's of any reportable incident. While the Company response team is mobilized to focus on source control and containment of the spill, O'Brien's coordinates communications with state and federal agencies and provides subject matter expertise in support of the response team.

We also have 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 eight bases along the gulf coast, from South Texas to East Louisiana. The CGA equipment stockpile is available to serve member oil spill response needs and includes open seas skimmers, 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 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, 2017, we had 63 full time employees, of which 20 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 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.

Corporate Offices

Our corporate offices are located at 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, 2017 was approximately $2.2 million. As of January 2017, a portion of our space in the building is being subleased through the lease expiration date for $0.5 million annually.

Code of Ethics

In January 2014, our board of directors adopted our current Code of Business Conduct and Ethics ("Code of Conduct") which 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 we make these documents available free of charge at our website at http://www.contango.com

Table of Contents

as soon as reasonably practicable after they are filed or furnished with the SEC. 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 cooler 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 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 continued 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. Natural gas and crude oil prices remained relatively low through 2017. While natural gas prices have remained consistent with 2017 levels, crude oil prices increased slightly during the final months of 2017 and throughout early 2018. 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 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 ability of the members of the Organization of Petroleum Exporting Countries and other oil exporting nations to agree to and maintain oil price and production controls.
- The level of LNG imports and any LNG exports.
- The level of natural gas exports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- Access to pipelines and gas processing plants.
- The loss of tax credits and deductions.

Table of Contents

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. The Company may utilize financial derivative contracts, such as swaps, costless collars and puts on commodity prices, to reduce exposure to potential declines in commodity prices, however, these derivative contracts may not be sufficient to mitigate the effect of lower commodity prices.

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

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

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

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of undeveloped acreage and/or 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, borrowings under our senior secured revolving credit agreement and/or proceeds from non-core asset sales. 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 currently available under our senior secured revolving credit agreement. As part of the regular redetermination schedule, the borrowing base on our revolving credit agreement was redetermined at $115 million effective November 9, 2017 and through May 01, 2018. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness is uncertain and will be affected by our future performance and events or circumstances beyond our control. For example, at December 31, 2017, we were not in compliance with the Current Ratio covenant under our credit agreement, although we obtained a waiver for such non-compliance. Any future failure to comply with these covenants could result in an event of default under such indebtedness and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under any of our other outstanding indebtedness.

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 rely on third-party contract operators to drill, complete and manage some of our wells, production platforms, pipelines and processing facilities and, as a result, we have limited control over the daily operations of such equipment and facilities.

We depend upon the services of third-party operators to operate drilling rigs, completion operations, offshore 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 operations are down or our production is shut-in when 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.

Failure of our working interest partners to fund their share of development costs could result in the delay or cancellation of future projects, which could have a materially adverse effect on our financial condition and results of operations.

Natural gas and crude oil prices remained relatively low through most of 2017, and while natural gas prices have remained consistent with 2017 levels, crude oil prices increased slightly during the final months of 2017 and throughout early 2018. An extended or more severe downturn could have material adverse effects on the liquidity of our working interest partners. Our working interest partners must be able to fund their share of investment costs through cash flow from operations, external credit facilities, or other sources. If our partners are not able to fund their share of costs, it could result in the delay or cancellation of future projects, resulting in a reduction of our reserves and production, which could have a materially adverse effect on our financial condition and results of operations.

We are exposed to the credit risks of our customers and derivative counterparties, and any material nonpayment or nonperformance by our customers or derivative counterparties could have a materially adverse effect on our financial condition and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. To the extent one or more of our significant customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our customers or our derivative counterparties could have a materially adverse effect on our financial condition and results of operations.

Table of Contents

Repeated offshore production shut-ins can possibly damage our well bores.

Our offshore well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill additional wells.

Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Further, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.

In order to prepare these estimates, our independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value.

Approximately 35% of our total estimated proved reserves at December 31, 2017 were proved undeveloped reserves. The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

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. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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, 2017 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2017. For our condensate and natural gas liquids, the average West Texas Intermediate (Cushing) posted price was $51.34 per barrel for offshore and onshore Southern Delaware Basin volumes, as prepared by Cobb, and the average West Texas Intermediate (Plains) posted price was $47.79 per barrel for all other onshore volumes, as prepared by NSAI. For our natural gas, the average Henry Hub spot price was $2.98 per MMBtu for all offshore and onshore volumes, as prepared by both Cobb and NSAI. Assuming strip pricing as of March 1, 2018 through 2022 and keeping pricing flat thereafter, instead of 2017 SEC pricing, while leaving all other parameters unchanged, the Company’s proved reserves would have been 188.6 Bcfe and the PV-10 value of proved reserves would have been $258.3 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 – PV-10".

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.

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;

Table of Contents

- pressures;
- fires;
- explosions and blowouts;
- pipe or cement failures;
- environmental hazards, such as natural gas leaks, oil and produced water 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;
- stockholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas so as to minimize emissions of GHGs;
- natural disasters; and
- adverse weather conditions.

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

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

The potential lack of availability of, or 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, such as the Southern Delaware Basin, 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.

Table of Contents

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 and produced water spills, pipeline and tank ruptures or unauthorized discharges of brine, toxic gases, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment.
- Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
- Repeated shut-ins of our well bores could significantly damage our well bores.
- Required workovers of existing wells that may not be successful.

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

- Injury or loss of life.
- Reservoir damage.
- Severe damage to and destruction of property or equipment.
- Pollution and other environmental and natural resources damage.
- Restoration, decommissioning or 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. For example, our total production for the year ended December 31, 2017 declined by 0.4 Mmcfe/d as a result of downtime associated with the impact of Hurricane Harvey. 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 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.

Our 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. 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, but the rule was not adopted. In December 2016, the CFTC proposed a new version of the rule, with respect to which the comment period has closed but a final rule has not been issued. 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. In addition the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we currently qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

In addition, if any of our swaps do not qualify for the commercial end-user exception, 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 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

Table of Contents

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.

If prices remain at current levels or decline further, we will likely incur further 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 further in 2018, we may be required to record further 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 cost basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value.

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

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

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

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

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and may continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. While no comprehensive climate change legislation has been implemented to date at the federal level, the EPA and states and groupings of states have considered or pursued cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In particular, 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 also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations.

Table of Contents

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published a final rule establishing New Source Performance Standards ("NSPS") Subpart OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards, but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect. Future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our or our customers' operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. Moreover, in December 2015, the United States joined other countries of the United Nations in preparing an agreement requiring member countries to review and establish goals for limiting GHG emissions. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions but, rather, includes pledges to voluntarily limit or reduce future emissions. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. 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 international, federal or state 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. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, which could reduce the demand for the oil and natural gas we produce and lower the value of our reserves.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. 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. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC, or the FTC, we could be subject to substantial penalties and fines.

Section 1(b) of the NGA exempts natural gas gathering facilities from the FERC's jurisdiction. We believe that the gas gathering facilities we own meet the traditional tests the FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Our failure to comply with this or other laws and regulations administered by the FERC could subject us to substantial penalties, as described in Part I, Item 1: "Business—Governmental Regulations and Industry Matters."

Under the 2005 Act and implementing regulations, the FERC prohibits market manipulation in connection with the purchase or sale of natural gas. The CFTC has similar authority under the Commodity Exchange Act and regulations

Table of Contents

it has promulgated thereunder with respect to certain segments of the physical and futures energy commodities market including oil and natural gas. The FTC also prohibits manipulative or fraudulent conduct in the wholesale petroleum market with respect to sales of commodities, including crude oil, condensate and natural gas liquids. These agencies have substantial enforcement authority, including the potential ability to impose maximum penalties for violations in excess of $1 million per day for each violation. Following their adoption, the maximum penalties prescribed by these regulations have been subject to annual adjustment for inflation. The FERC has also imposed requirements related to reporting of natural gas sales volumes that may impact the formation of prices indices. Additional rules and legislation pertaining to these and other matters may be considered or adopted from time to time. Our failure to comply with these or other laws and regulations administered by these agencies could subject us to substantial penalties, as described in Part I, Item 1: "Business—Governmental Regulations and Industry Matters."

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

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

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

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

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

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

Table of Contents

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

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

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated or significantly changed as a result of future legislation.

Recently enacted legislation, commonly referred to as the Tax Cuts and Jobs Act, made significant changes to U.S. tax laws. While past legislative proposals have included changes to certain key U.S. federal income tax provisions currently available to oil and gas companies, including (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures, these specific changes were not included in the Tax Cuts and Jobs Act. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. However, the Tax Cuts and Jobs Act (i) eliminates the deduction for certain domestic production activities, (ii) imposes new limitations on the utilization of net operating losses, and (iii) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. Future changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on our business, financial condition, results of operations and cash flows.

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

Our oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing the operation and maintenance of our facilities, the discharge of materials into the environment and environmental protection. Failure to comply with such rules and regulations could result in the assessment of sanctions, including administrative, civil and criminal penalties, investigatory, remedial and corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects and the issuance of orders limiting or prohibiting some or all of our operations in affected areas. These laws and regulations may:

- require that we obtain permits before commencing drilling or other regulated activities;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial penalties for pollution resulting from drilling and production operations.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental natural resource and property damages. We maintain insurance coverage for sudden and accidental environmental damages; however, it is possible that coverage might not be sufficient in a catastrophic event. Accordingly, we may be subject to liability, or we may be required to cease production from properties in the event of environmental damages. The trend in environmental laws and regulations is to place more stringent restrictions and

Table of Contents

limitations on activities that may affect the environment. For example, in October 2015, the EPA issued a final rule lowering the National Ambient Air Quality Standard for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either “attainment/unclassifiable” or “unclassifiable” but had not yet issued non-attainment designations for the remaining areas of the U.S. not addressed in the November 2017 final rule. States are also expected to implement requirements as a result of this NAAQs final rule, which could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Compliance with this final rule could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital or operating expenditures. In another example, in June 2015, the EPA and the Corps published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States including wetlands, but legal challenges to this rule followed. The 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the U.S. Supreme Court agreed to hear the case. The EPA and Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act’s jurisdiction, and published a proposed rule in November 2017 specifying that the contested June 2015 rule would not take effect until two years after the November 2017 proposed rule was finalized and published in the Federal Register. Recently, on January 22, 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; consequently, while implementation of the 2015 rule currently remains stayed, the previously-filed district court cases will be allowed to proceed. As a result of these recent developments, future implementation of the June 2015 rule is uncertain at this time but to the extent any rule expands the scope of the Clean Water Act’s jurisdiction, drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, we can provide no assurance that our future compliance with existing laws and regulations, these recently adopted rulemakings, or any new or amended legal requirements will not have a material adverse effect on our business, financial condition and results of operations.

An accidental release of pollutants into the environment may cause us to incur significant costs and liabilities.

We may incur significant environmental costs liabilities in our business as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations, and due to historical industry operations and waste disposal practices. We currently own, operate or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. 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. For example, an accidental release resulting from the drilling of a well, could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property and natural resource damages as well as monetary fines or penalties for related violations of environmental laws or regulations. Moreover, certain environmental statutes impose strict, joint and several liability for these costs and liabilities without regard to fault or the legality of our conduct. Under these environmental laws and regulations, 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 or other decommissioning activities to prevent future contamination. We may not be able to recover some or any of these costs from insurance.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand or other proppant and chemical additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or similar state agencies, but several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process. For example, in February 2014, the EPA asserted regulatory authority pursuant to the SDWA Underground Injection Control program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities. The EPA also published final rules under the CAA in 2012 and in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Additionally, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants and, in May 2014, published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The BLM published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands. However, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule, the BLM appealed the decision to the U.S. Circuit Court of Appeals for the Tenth Circuit in July 2016, the appellate court issued a ruling in September 2017 to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in response to the BLM's issuance of a proposed rulemaking to rescind the 2015 rule and, in December 2017, the BLM published a final rule rescinding the March 2015 rule. In January 2018, litigation challenging the BLM's rescission of the 2015 rule was brought in federal court. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances, including as a result of water withdrawals for fracturing in times or areas of low water availability or due to surface spills during the management of fracturing fluids, chemicals or produced water.

Moreover, from time to time, Congress has considered, but not enacted, legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, certain states, including Texas and Wyoming, where we conduct operations, have adopted and other states are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach of the State of New York in 2015. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

We may be subject to additional supplemental bonding under the BOEM financial assurance requirements.

Energy companies conducting oil and natural gas lease operations offshore on the OCS are required by the BOEM, among other obligations, to conduct decommissioning within specified times following cessation of offshore producing activities, which decommissioning includes the plugging of wells, removal of platforms and other facilities, and the clearing of obstacles from the lease site sea floor. To cover a lease operator's decommissioning obligations, the BOEM generally requires that lessees demonstrate financial strength and reliability according to regulations or otherwise post bonds or other acceptable financial assurances that such future obligations will be satisfied. As an operator, we are required to post surety bonds of $200,000 per lease for exploration and $500,000 per lease for developmental activities as part of our general bonding requirements, as well as the posting of additional supplemental bonds to cover, among other things, our decommissioning obligations. We typically post surety bonds with the BOEM to satisfy our general and supplemental bonding requirements.

The BOEM continues to consider the adoption or enforcement of more stringent financial assurance regulatory initiatives that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural gas exploration and production operations conducted offshore on the federal OCS. In particular, the BOEM issued an updated NTL #2016-N01 that became effective in September 2016 and bolsters the financial assurance requirements offshore lessees on the OCS, including the Gulf of Mexico, must satisfy with respect to their decommissioning liabilities. If the BOEM determines under NTL #2016-N01 that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. During 2017, however, with the issuance of Order 3350, the BSEE and the BOEM have been directed to reconsider a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities, including, for example, NTL #2016-N01, and provide recommendations on whether such regulatory initiatives should continue to be implemented. Consequently, during 2017, the BOEM extended the start date for implementing NTL #2016-N01 indefinitely beyond June 30, 2017. This extension currently remains in effect; however, the BOEM reserved the right to re-issue sole liability orders in the future, including in the event that it determines there is a substantial risk of nonperformance of the interest holder’s decommissioning sole liabilities. Following completion of its review, the BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the review is completed and the BOEM determines what additional financial assurance

Table of Contents

may be required by us, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties.

If we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition. Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning obligations at those OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material.

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

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. The agency is responsible for leading the most aggressive and comprehensive reforms to offshore oil and natural gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well and blowout preventer design and workplace safety to corporate accountability. However, as a result of the issuance of Order 3350 during 2017, the BSEE is reconsidering a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities. For example, on December 29, 2017, the BSEE published proposed revisions to its regulations regarding offshore drilling safety equipment, which proposal includes the removal of the requirement for offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) is operational and functioning as designed in the most extreme conditions. The December 2017 proposed rule has not been finalized and there remains substantial uncertainty as to the scope and extent of any revisions to existing oil and gas safety and performance-related regulations and other regulatory initiatives that ultimately will be adopted by the BSEE pursuant to the agency’s review process.

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

In addition to the enforcement actions specified above, the BSEE can assess civil penalties if: (i) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or (ii) the violation resulted in a threat of serious harm or damage to human life or the environment. In January 2018, the BSEE published a final rule that increased the maximum civil penalty rate for Outer Continental Shelf Lands Act violations to $43,576 a day for each violation. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

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

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

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

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

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

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

- Problems integrating the purchased operations, personnel or technologies.
- Unanticipated costs.
- Diversion of resources and management attention from our exploration business.
- Entry into regions or markets in which we have limited or no prior experience.
- Potential loss of key employees of the acquired organization.

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

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

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

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

Table of Contents

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

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

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

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

Increases in interest rates could adversely impact our business, share price and our ability to issue equity or incur debt for acquisitions, capital expenditures or other purposes.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Rising interest rates could reduce the amount of cash we generate and materially adversely affect our liquidity. Moreover, the trading price of our common stock is sensitive to changes in interest rates and could be materially adversely affected by any increase in interest rates.

Assuming an outstanding balance on our credit facility of $85.4 million, an increase of one percentage point in the interest rates would have resulted in an increase in interest expense during 2017 of $0.9 million. Accordingly, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates.

Cybersecurity breaches and information technology failures could harm our business by increasing our costs and negatively impacting our operations.

We rely extensively on information technology systems, including Internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;

- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;

- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;

- A cyber attack on third party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;

- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;

- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and

- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer’s or supplier’s data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

RISK FACTORS RELATED TO AN INVESTMENT IN OUR COMMON STOCK

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

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

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for crude oil, natural gas and natural gas liquids, domestically and globally;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;

Table of Contents

- changes in government and environmental regulation;
- general market, economic and political conditions, domestically and globally;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us, our significant stockholders or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

Average natural gas and crude oil prices declined dramatically beginning in early 2015 and have remained relatively low since then. In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This decline in commodity prices and stock market volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

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

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

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our board of directors is authorized, without further stockholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. We are authorized to issue up to five million shares of preferred stock. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

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

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

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

As of December 31, 2017, we had 94,833 stock options outstanding to purchase shares of our common stock outstanding, all of which were fully vested.

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

Table of Contents

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

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

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

We are subject to the Delaware business combination law.

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

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

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

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

Table of Contents

Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions.

As an oil and gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

As of December 31, 2017, we operated all of our offshore wells, with an average working interest of 54%, and operated 48% of our onshore wells with an average working interest of 69%. As of December 31, 2017, our properties were located in the following regions: Offshore Gulf of Mexico, Southeast Texas, South Texas, West Texas and Other.

Development, Exploration and Acquisition Expenditures

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties, exploration costs incurred in the search for new reserves from unproved properties and costs incurred in the development of those properties for the periods indicated (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Property acquisition costs:			
Unproved	$ 6,540	$ 29,767	$ 11,453
Proved	—	—	—
Exploration costs	8,158	9,126	29,477
Development costs	45,016	1,890	20,120
Total costs	$ 59,714	$ 40,783	$ 61,050

Included in unproved property acquisition costs for the year ended December 31, 2017, is $5.9 million related to our acquisition of unproved property in the Southern Delaware Basin.

Included in unproved property acquisition costs for the year ended December 31, 2016, is $27.0 million related to our acquisition of unproved property in the Southern Delaware Basin.

Included in unproved property acquisition costs for the year ended December 31, 2015, is $5.0 million related to Natrona and Weston counties, Wyoming.

Table of Contents

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

	Year Ended December 31,		
	2017	2016	2015
Property acquisition costs	$ —	$ —	$ —
Exploration costs	—	—	—
Development costs	429	395	4,503
Total costs incurred	$ 429	$ 395	$ 4,503

Drilling Activity

The following tables show our exploratory and developmental drilling activity for the periods indicated. In the tables, “gross” wells refer to wells in which we have a working interest, and “net” wells refer to gross wells multiplied by our working interest in such wells.

	Year Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	1	0.5	1	0.8	5	2.9
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	1	0.4	—	—	1	0.8
Non-productive (offshore)	—	—	—	—	—	—
Total	2	0.9	1	0.8	6	3.7

	Year Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive (onshore)	4	1.9	—	—	9	5.3
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	4	1.9	—	—	9	5.3

Exploration and Development Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of crude oil, natural gas and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres.

The following table shows the approximate developed and undeveloped acreage that we have an interest in, by region, at December 31, 2017.

	Developed Acreage (1)		Undeveloped Acreage (1)	
	Gross	Net (2)	Gross	Net (2)
Offshore GOM	9,618	6,828	—	—
Southeast Texas	22,044	13,143	7,262	3,994
South Texas	78,990	34,537	10,617	6,299
West Texas	6,139	2,883	10,316	3,929
Other (3)	9,956	5,735	62,517	41,733
Total	126,747	63,126	90,712	55,955

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.

Table of Contents

(2) Net acres represent the number of acres attributable to our proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).
(3) Other includes acreage in Louisiana, Mississippi, Wyoming, North Texas and East Texas.
Some of our offshore and onshore leases will expire over the next three years as follows, unless we establish production or take action to extend the terms of these leases:

	Year ending December 31,					
	2018		2019		2020	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore GOM	—	—	—	—	—	—
Southeast Texas	328	245	272	264	—	—
South Texas	3,618	1,809	100	50	—	—
West Texas	3,174	1,587	2,291	1,059	650	299
North Texas	4,195	—	—	—	—	—
Wyoming	8,267	10,256	7,880	6,039	5,521	4,417
Total	19,582	13,897	10,543	7,412	6,171	4,716

Production, Price and Cost History

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

Productive Wells

Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a "productive" well. The following table sets forth the number of gross and net productive natural gas and oil wells in which we owned an interest as of December 31, 2017:

	Natural Gas Wells		Oil Wells	
	Gross Wells (1)	Net Wells (2)	Gross Wells (1)	Net Wells (2)
Offshore GOM	11	6.0	—	—
Southeast Texas	34	19.7	47	25.3
South Texas	171	74.4	46	22.1
West Texas	—	—	6	2.9
Other	23	4.9	12	4.7
Total	239	105.0	111	55.0

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

Natural Gas and Oil Reserves

Estimates of proved reserves and future net revenue as of December 31, 2017, 2016 and 2015 were prepared by NSAI and Cobb, our independent petroleum engineering firms in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE"). Approximately 69% and 31% of the proved reserves estimates shown herein at December 31, 2017 have been independently prepared by Cobb and NSAI, respectively. Cobb prepared the proved reserves estimates as of December 31, 2017, 2016 and 2015 for all of our offshore properties and our onshore

Southern Delaware Basin reserves as of December 31, 2017, while NSAI prepared the proved reserves estimates as of December 31, 2017, 2016 and 2015 for our remaining onshore properties.

The technical individual at NSAI responsible for the preparation of our reserve estimates as of December 31, 2017, 2016, and 2015 has over 15 years of experience in the estimation and evaluation of reserves; is a licensed professional engineer in the state of Texas; and holds a Bachelor of Science Degree in Petroleum Engineering from the University of Tulsa. The technical individual at Cobb responsible for overseeing the preparation of our reserve estimates

Table of Contents

as of December 31, 2017, 2016, and 2015 has over 40 years of experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas; holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University; is a member of the SPE; and is a member of the Society of Petroleum Evaluation Engineers.

The estimates of proved reserves and future net revenue as of December 31, 2017, 2016 and 2015 were reviewed by our corporate reservoir engineering department that is independent of the operations department. The corporate reservoir engineering department interacts with geoscience, operating, accounting and marketing departments to review the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. All relevant data is compiled in a computer database application to which only authorized personnel are given access rights. Our Senior Vice President - Engineering is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for reviewing any reserves estimates prepared by our independent petroleum engineering firms. Our Senior Vice President - Engineering has a Bachelor of Science degree in Petroleum Engineering from the University of Texas and over 40 years of industry experience with positions of increasing responsibility. He reports directly to our President and Chief Executive Officer. Reserves are also reviewed internally with senior management and presented to our board of directors in summary form on a quarterly basis.

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

Table of Contents

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

	December 31, 2017	2016	2015
Crude Oil and Condensate (MBbl) (1)			
Developed	3,364	2,158	2,869
Undeveloped	7,285	1,266	1,922
Total	10,649	3,424	4,791
Natural Gas (MMcf) (1)			
Developed	82,133	95,396	113,952
Undeveloped	9,586	9,657	12,176
Total	91,719	105,053	126,128
Natural Gas Liquids (MBbl) (1)			
Developed	3,596	3,509	4,354
Undeveloped	2,011	850	1,040
Total	5,607	4,359	5,394
Total MMcfe			
Developed	123,895	129,399	157,288
Undeveloped	65,359	22,351	29,950
Total (2)	189,254	151,750	187,238
Proved developed reserves percentage	65 %	85 %	84 %
Prices utilized in estimates (3):			
Crude oil ($/Bbl)	$ 47.41	$ 38.67	$ 44.53
Natural gas ($/MMBtu)	$ 2.92	$ 2.43	$ 2.63
Natural gas liquids ($/Bbl)	$ 18.59	$ 13.62	$ 14.41

(1) Excludes reserves attributable to our 37% interest in Exaro.
(2) During the year ended December 31, 2017, proved reserves increased by approximately 37.5 Bcfe primarily due to 63.1 Bcfe of new additions and extensions related to our drilling program and a 9.9 Bcfe positive revision of reserve estimates due to higher commodity prices, partially offset by 20.1 Bcfe in 2017 production and a 12.2 Bcfe decrease due to a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded.
(3) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices were adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

PV 10

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

42

Table of Contents

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

	December 31,	
	2017	2016
Pre-tax net present value, discounted at 10%	$ 257,283	$ 166,228
Future income taxes, discounted at 10%	(1,376)	—
Standardized measure of discounted future net cash flows	$ 255,907	$ 166,228

The following table reflects our estimated proved reserves by category as of December 31, 2017 (dollars in thousands):

	Crude Oil and Condensate (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved		PV - 10
Proved developed producing	3,157	73,694	3,066	111,037	59	%	$ 186,098
Proved developed non-producing	207	8,439	530	12,858	7	%	14,625
Proved undeveloped	7,285	9,586	2,011	65,359	34	%	56,560
Total	10,649	91,719	5,607	189,254	100	%	$ 257,283

Our estimated net proved reserves as of December 31, 2017 were approximately 34% crude oil and condensate, 48% natural gas and 18% natural gas liquids.

Proved Developed Reserves

Total proved developed reserves declined slightly from 129.4 Bcfe at December 31, 2016 to 123.9 Bcfe at December 31, 2017. This decline is primarily due to a 20.1 Bcfe decrease attributable to production during the year and a 1.7 Bcfe negative performance revision, partially offset by 10.7 Bcfe of extensions and additions related to our drilling program and a 7.0 Bcfe positive revision of reserve estimates due to higher commodity prices.

The following table presents the changes in our total proved developed reserves for the year ended December 31, 2017:

	Proved Developed Reserves (Mmcfe)
Proved developed reserves at December 31, 2016	129,399
Revisions of previous estimates (1)	7,008
Extensions, discoveries and other additions (2)	10,743
Purchase of minerals in place	—
Disposition of reserves in place (3)	(1,459)
Production	(20,123)
Negative revisions related to performance	(1,673)
Proved developed reserves at December 31, 2017	123,895

(1) Positive revisions due to higher commodity prices.

(2) Extensions, discoveries and additions are primarily related to our assets in the Southern Delaware Basin in West Texas.
(3) Related to the sale of our assets in the North Bob West area and our operated assets in the Escobas area, both located in Southeast Texas.

Proved Undeveloped Reserves

Total proved undeveloped reserves ("PUDs") increased from 22.4 Bcfe at December 31, 2016 to 65.4 Bcfe at December 31, 2017. As noted in the table below, this increase was primarily attributable to extensions and additions primarily related to the successful development of assets in West Texas, partially offset by the PUDs removed due to the SEC's five year rule.

Future drilling plans and timelines are re-evaluated at the end of each calendar year based on updated reserve reports, current drilling cost estimates and product price forecast. Our development plan prioritizes reserves based on the capital requirements and net present value of potential wells. Generally, our plan is to convert PUDs to developed reserves in an order that is based on their economic importance and impact on production and cash flow, but other factors may be considered such as technical merit, product type, location and available working interest partners. The

Table of Contents

PUD conversion rate in 2017 and 2016 was 0% and 0%, respectively, of the total net present value of the Company's total PUDs at the beginning of the applicable year.

The Company annually reviews any PUDs to ensure their development within five years from the date of originally adding the reserves. The Company's financial resources are expected to be sufficient to drill all of the remaining 65.4 Bcfe of proved undeveloped reserves within the five year period. Development costs relating to the 65.4 Bcfe at December 31, 2017 are projected to be approximately $124.6 million over the next five years.

The following table presents the changes in our total proved undeveloped reserves for the year ended December 31, 2017:

	Proved Undeveloped Reserves (Mmcfe)
Proved undeveloped reserves at December 31, 2016	22,351
Revisions of previous estimates (1)	2,889
Extensions, discoveries and other additions (2)	52,333
Purchase of minerals in place	—
Expired undeveloped reserves	(12,214)
Disposition of reserves in place	—
Conversion to proved developed	—
Proved undeveloped reserves at December 31, 2017	65,359

(1) Positive revisions due to higher commodity prices.

(2) Extensions, discoveries and additions are primarily related to our assets in the Southern Delaware Basin in West Texas.

Significant Properties

Summary proved reserve information for our properties as of December 31, 2017, by region, is provided below (excluding reserves attributable to our investment in Exaro) (dollars in thousands):

	Proved Reserves				
Regions	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (Mmcfe)	PV - 10 (1)
Offshore GOM	432	61,430	1,889	75,359	$ 124,316
Southeast Texas	2,092	11,448	1,146	30,874	37,005
South Texas	1,984	10,196	598	25,687	37,060
West Texas	5,944	8,064	1,965	55,516	55,879
Other	197	581	9	1,818	3,023
Total	10,649	91,719	5,607	189,254	$ 257,283

(1) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first

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

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

Table of Contents

Reserves Attributable to our Investment in Exaro

Estimates of proved reserves and future net revenue as of December 31, 2017 and 2016 associated with our investment in Exaro, which we account for using the equity method, were prepared by Von Gonten in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE.

Reserves as of December 31, 2017 and 2016 were reviewed by our corporate reservoir engineering department as described above. The technical individual at Von Gonten responsible for overseeing the preparation of our reserve estimates as of December 31, 2017 and December 31, 2016 has over 17 years of practical experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas; holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University; and is a member in good standing of the SPE.

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

	December 31, 2017		December 31, 2016		December 31, 2015	
Crude Oil (MBbl)						
Developed	325		360		442	
Undeveloped	4		—		—	
Total	329		360		442	
Natural Gas (MMcf)						
Developed	28,443		30,441		36,074	
Undeveloped	303		—		—	
Total	28,746		30,441		36,074	
Total MMcfe						
Developed	30,390		32,600		38,724	
Undeveloped	329		—		—	
Total (3)	30,719		32,600		38,724	
Proved developed reserves percentage	99	%	100	%	100	%
Standardized measure (1)	$ 24,366		$ 19,778		$ 31,298	
Prices utilized in estimates (2)						
Crude oil ($/Bbl)	$ 48.91		$ 39.60		$ 44.28	
Natural gas ($/MMBtu)	$ 3.02		$ 2.44		$ 2.71	

(1) The Company's share of the standardized measure of discounted future net cash flows attributable to our investment in Exaro does not include the effect of income taxes because Exaro is treated a partnership for tax purposes. Exaro allocates any income or expense for tax purposes to its partners.
(2) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.
(3) During the year ended December 31, 2017, the decrease in Exaro’s proved reserves attributable to our Investment in Exaro was approximately 1.9 Bcfe.

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of December 31, 2016, 2015 and 2014 are disclosed in "Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Disclosures (Unaudited)". Reserves as of December 31, 2016, 2015 and 2014 were based on reserve reports generated by NSAI and Cobb, while the reserves associated with our 37% investment in Exaro were prepared by Von Gonten.

Item 3. Legal Proceedings

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

Table of Contents

In July 2010, several parties associated with a limited partnership, formed to invest in oil and gas properties, and that was dissolved in 1995, filed suit against a subsidiary of the Company and several co-defendants in the district court for Madison County in Texas. The plaintiffs claim to own or have rights in certain oil and gas properties situated in Madison County, Texas by virtue of the partnership having interests in addition to those it held of record at the time of its dissolution, which were distributed to the partners in connection with such dissolution. A predecessor of the subsidiary of the Company involved in this case acquired a portion of the interests now claimed by the plaintiffs from a successor to the general partner of the aforementioned partnership in 2000. The case went to trial in December 2017. As the Court did not allow virtually all of the plaintiff's claims, a nominal settlement agreement was executed to settle all claims.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the applicable state Court of Appeals. In the fourth quarter of 2017 the Court of Appeals issued its opinion and affirmed the trial court's summary decision. The Company continues to vigorously defend this lawsuit and has filed a motion for rehearing with the Court of Appeals, and if denied, will petition the Texas Supreme Court.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgement in the Company's favor. The plaintiff has filed a motion for rehearing. The Company continues to vigorously defend this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Our common stock is listed on the NYSE American under the symbol "MCF". The table below shows the high and low sales prices per share of our common stock for the periods indicated.

	High	Low
Year Ended December 31, 2017		
Quarter Ended March 31, 2017	$ 10.15	$ 5.62
Quarter Ended June 30, 2017	$ 8.19	$ 5.83
Quarter Ended September 30, 2017	$ 6.89	$ 3.97
Quarter Ended December 31, 2017	$ 5.43	$ 2.22
Year Ended December 31, 2016		
Quarter Ended March 31, 2016	$ 12.84	$ 3.68
Quarter Ended June 30, 2016	$ 14.14	$ 10.52
Quarter Ended September 30, 2016	$ 12.85	$ 8.25
Quarter Ended December 31, 2016	$ 11.98	$ 7.43

From the period from January 1, 2018 to March 5, 2018, our common stock traded at prices between $2.80 and $5.97 per share. During the quarter ended September 30, 2016, we completed an underwritten public offering of 5,360,000 shares for net proceeds of approximately $50.5 million.

General

The following descriptions are summaries of material terms of our common stock, preferred stock, certificate of incorporation and bylaws. This summary is qualified by reference to our certificate of incorporation, bylaws and the designations of our preferred stock, which are filed as exhibits to this report on Form 10-K, and by the provisions of applicable law.

Common Stock

We are authorized to issue up to 50 million shares of common stock. As of March 5, 2018, there were approximately 30.9 million shares of common stock issued and 25.5 million shares of common stock outstanding held by approximately 228 registered shareholders.

Holders of common stock are entitled to one vote for each share held of record on each matter submitted to a vote of stockholders and, in the event of liquidation, to share ratably in the distribution of assets remaining after payment of liabilities (including preferential distribution and dividend rights of holders of preferred stock). Holders of common stock have no cumulative rights. The holders of a plurality of the outstanding shares of the common stock have the ability to elect all of the directors.

Holders of common stock have no preemptive or other rights to subscribe for shares. Holders of common stock are entitled to such dividends as may be declared by the board of directors out of funds legally available. Therefore, any decision to pay future dividends on our common stock will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, capital requirements and other factors our board of directors may deem relevant. We do not anticipate paying any cash dividends on our common stock in the foreseeable future, as we currently intend to retain all future earnings to fund the development and growth of our business. Our credit facility with Royal Bank of Canada and other lenders currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Preferred Stock

Our board of directors is authorized, without further stockholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. We are authorized to issue up to five million shares of preferred stock. No preferred stock was outstanding at December 31, 2017.

Table of Contents

Share-Based Compensation

The following table sets forth information about our equity compensation plans at December 31, 2017:

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans	
Amended and Restated 2009 Incentive Compensation Plan - approved by security holders	—	$ —	2,002,492	*
2005 Stock Incentive Plan ("Crimson Plan")	94,833	$ 57.69	—	

* Excludes 382,744 Performance Stock Units granted in 2016 and 2017.

Amended and Restated 2009 Incentive Compensation Plan

On September 15, 2009, the Company's board of directors (the "Board") adopted the Contango Oil & Gas Company Equity Compensation Plan (the "Original 2009 Plan"), which was approved by shareholders on November 19, 2009. On April 10, 2014, the Board amended and restated the Original 2009 Plan through the adoption of the Contango Oil & Gas Company Amended and Restated 2009 Incentive Compensation Plan (the "2009 Plan"), which was approved by shareholders on May 20, 2014. The 2009 Plan provides for both cash awards and equity awards (such as restricted stock, performance stock units and options) to officers, directors, employees and consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Stock options issued under the 2009 Plan must have an exercise price equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant officers and employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options granted generally expire after five or ten years. The vesting schedule for all equity awards varies from immediately to over a four-year period.

Effective January 1, 2014, the Company implemented performance-based long-term bonus plans under the 2009 Plan for the benefit of all employees through a Cash Incentive Bonus Plan ("CIBP") and a Long-Term Incentive Plan ("LTIP"). The specific performance metrics and targeted performance goals under the CIBP are approved annually, in advance, by the Compensation Committee and/or the Board. Upon achieving the performance levels established each year, bonus awards under the CIBP will be calculated as a percentage of base salary of each employee for the plan year. The CIBP awards for each year are expected to be disbursed in the first quarter of the following year. Employees must be employed by the Company at the time that awards are disbursed to be eligible. Prior to the 2017 performance year, the LTIP metrics and performance measures were also determined, in advance, by the Board, with ultimate grants for a performance year determined at the end of the performance year based on performance compared to the previously established goals. The ultimate LTIP awards for each year were also distributed during the first quarter of the following year with a three year vesting period. Beginning with the 2017 performance year, the Company discontinued the practice of awarding LTIP grants on a look-back basis based on performance compared to operational goals, and implemented the policy of determining an appropriate number of performance stock units (“PSUs”) to be granted to all employees at the beginning of the year, with a specified number of those granted shares vesting ratably, typically over a three period. The other portion of those grants will vest at the end of a three year performance period, with the ultimate number of shares to be issued based on the Company’s stock performance vs. that of the Company’s peer group during that three year period.

The CIBP awards will be paid in cash while the LTIP awards will consist of restricted common stock, PSUs and/or stock options that vest over three or four years. The number of shares of restricted common stock, the PSUs and the number of shares underlying the stock options granted will be determined based upon the fair market value of the common stock on the date of the grant.

Table of Contents

Restricted Stock Awards

During the year ended December 31, 2017, the Company granted 457,701 restricted stock awards under the 2009 Plan to officers, employees and directors of the Company, while 137,021 restricted shares issued under the 2009 Plan were forfeited by former employees and are available to be reissued. During the year ended December 31, 2016, 580,141 restricted stock awards were granted under the 2009 Plan to officers, employees and directors of the Company, while 17,864 restricted shares were forfeited by former employees and are available to be reissued. During the year ended December 31, 2015, 270,091 restricted stock awards were granted under the 2009 Plan to officers, employees and directors of the Company pursuant to the LTIP, while 12,534 restricted shares were forfeited by former employees and are available to be reissued. As of December 31, 2017, there were 731,073 shares of unvested restricted stock outstanding.

Performance Stock Units

During the year ended December 31, 2017, the Company granted 30,000 PSUs to a new employee, at a weighted average fair value of $8.32 per unit and 160,908 PSUs to executive officers, as part of their overall compensation package, at a value of $13.91 per unit. All prices were determined using the Monte Carlo simulation model. Also during the year, 99,363 PSUs were forfeited by former employees.

During the year ended December 31, 2016, the Company issued 285,800 PSUs to all employees as part of its LTIP, at a fair value of $16.32 per unit, as determined using the Monte Carlo simulation method. Additionally, the Company issued 6,699 PSUs to new employees, at a fair value of $13.06 per unit, also determined using the Monte Carlo simulation method. Former employees forfeited 1,300 PSUs during the year ended December 31, 2016. PSUs represent a contractual right to receive shares of the Company's common stock. The settlement of PSUs may range from 0% to 300% of the targeted number of PSUs stated in the agreement contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PSUs vest and settlement is determined after a three year period.

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

2005 Stock Incentive Plan

The 2005 Plan was adopted by the Company's Board in conjunction with the Merger with Crimson. The plan expired on February 25, 2015 and therefore no additional shares are available for grant.

During the year ended December 31, 2017, 5,197 restricted stock awards previously issued under the 2005 Plan were forfeited by former employees, while 17,072 stock options previously issued were forfeited. During the year ended December 31, 2016, 1,226 restricted stock awards issued under the 2005 Plan were forfeited by former employees, while 4,556 stock options previously issued were forfeited. During the year ended December 31, 2015, the Company granted 7,030 restricted stock awards under the 2005 Plan to a new employee, while 189 restricted stock awards were forfeited by former employees. Additionally, during the year ended December 31, 2015, 13,473 stock options previously issued were forfeited. As of December 31, 2017, there were no shares of restricted stock outstanding and 94,833 stock options vested and exercisable under the 2005 Plan. The exercise price for such options ranges from

$28.96 to $60.33 per share, with an average remaining contractual life of three years.

Table of Contents

Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. No shares were purchased for the years ended December 31, 2017, 2016 and 2015. As of December 31, 2017, the Company has $31.8 million available under its share repurchase program.

In addition, the Company repurchased the following shares, outside of the repurchase program, from employees for the payment of withholding taxes due on vesting shares of restricted stock previously issued under our stock-based compensation plans:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under F
February 2017	174	$ 8.08	n/a	n/a
March 2017	11,693	$ 6.18	n/a	n/a
April 2017	10,998	$ 7.88	n/a	n/a
June 2017	116	$ 6.65	n/a	n/a
October 2017	22,421	$ 4.11	n/a	n/a
November 2017	276	$ 3.09	n/a	n/a
December 2017	2,690	$ 2.96	n/a	n/a

Table of Contents

Stock Performance Graph

The following graph compares the yearly percentage change from December 31, 2012 until December 31, 2017 in the cumulative total stockholder return on our common stock to the cumulative total return on the S&P Smallcap 600 Index and a peer group of independent oil & gas exploration companies selected by us.

As of December 31, 2016, the companies in our selected peer group included Carrizo Oil & Gas, Matador Resources, Bill Barrett, Denbury Resources, SRC Energy, Abraxas Petroleum, Sanchez Energy, EP Energy, Halcon Resources, W&T Offshore and Approach Energy (collectively, the “2016 Peer Group”). For the year ended December 31, 2017, we elected to use the same PSU peer group used under the Company’s LTIP to determine the number of shares of common stock to be issued to employees at the end of the three year performance period. That peer group consisted of: Abraxas Petroleum Corp, Approach Resources Inc, Bill Barrett Corp, Callon Petroleum Co, Carrizo Oil & Gas Inc, Denbury Resources Inc, Energen Corp, EP Energy Corp, Extraction Oil & Gas Inc, Halcon Resources Corp, Laredo Petroleum Inc, Matador Resources Co, Murphy Oil Corp, Oasis Petroleum Inc, QEP Resources Inc, Sanchez Energy Corp, SM Energy Co, SRC Energy Inc, W&T Offshore Inc, Whiting Petroleum Corp and WPX Energy Inc, (collectively, the “2017 Peer Group”).

Our common stock began trading on the NYSE American (previously NYSE MKT) on January 19, 2001 and before that had traded on the Nasdaq over-the-counter Bulletin Board. The graph assumes that a $100 investment was made in our common stock and each index on December 31, 2012, adjusted for stock splits and dividends. The stock performance for our common stock is not necessarily indicative of future performance.

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
Contango Oil & Gas Company	100.00	111.57	69.03	15.13	22.05	11.12
S&P Smallcap 600	100.00	141.31	149.45	146.50	185.40	209.94
2016 Peer Group	100.00	112.08	68.87	33.47	46.28	36.35
2017 Peer Group	100.00	129.55	80.05	40.40	62.52	48.93

Table of Contents

Item 6. Selected Financial Data

On October 1, 2013, the Company's board of directors approved a change in fiscal year end from June 30 to December 31. Unless otherwise noted, all references to "years" in this report refer to the twelve-month period which ends on December 31 of each year. The following selected financial data for the years ended December 31, 2017, 2016 and 2015 have been derived from the audited consolidated financial statements of Contango contained in this Form 10-K. The following selected financial data for the years ended December 31, 2014 and 2013 have been derived from the audited consolidated financial statements of Contango contained in our Form 10-K for the applicable fiscal year. The selected consolidated financial data (not including proved reserve information) set forth below is for continuing operations and should be read in conjunction with Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this Form 10-K.

Selected financial data for the years ended December 31, 2017, 2016, 2015, 2014 and 2013 include results of operations and cash flows of Crimson starting from October 1, 2013, the date of the Merger. Consolidated balance sheet and reserves information as of December 31, 2017, 2016, 2015, 2014 and 2013 include the balance sheet and reserves information of Crimson and its subsidiaries adjusted in accordance with the acquisition method of accounting, which requires that assets acquired and liabilities assumed in the Merger be recorded at their fair value at the date of acquisition with the difference between the purchase price and value of assets and liabilities be recorded as goodwill. No goodwill was recognized as a result of the Merger between Contango and Crimson.

Selected financial information for the five years ended December 31, 2017 is as follows (dollars in thousands, except per share amounts):

	Year Ended December 31				
	2017	2016	2015	2014	2013
Natural gas and oil sales (1)	$ 78,545	$ 78,183	$ 116,505	$ 276,458	$ 164,121
Income (loss) (2)	$ (17,643)	$ (58,029)	$ (335,048)	$ (21,874)	$ 41,362
Net income (loss) attributable to common stock	$ (17,643)	$ (58,029)	$ (335,048)	$ (21,874)	$ 41,362
Net income (loss) per share:					
Basic	$ (0.71)	$ (2.71)	$ (17.67)	$ (1.15)	$ 2.56
Diluted	$ (0.71)	$ (2.71)	$ (17.67)	$ (1.15)	$ 2.56
Weighted average shares outstanding:					
Basic	24,686	21,424	18,965	19,059	16,156
Diluted	24,686	21,424	18,965	19,059	16,158

	Year Ended December 31				
	2017	2016	2015	2014	2013
Working capital (deficit) (3)	$ (34,764)	$ (43,835)	$ (18,689)	$ (65,975)	$ (33,162)
Capital expenditures	$ 58,376	$ 38,966	$ 55,565	$ 188,529	$ 62,552

Long term debt	$ 85,380	$ 54,354	$ 115,446	$ 63,359	$ 90,000
Shareholders’ equity	$ 224,600	$ 236,405	$ 237,843	$ 567,466	$ 593,050
Total assets	$ 381,453	$ 376,514	$ 416,756	$ 843,415	$ 910,304
Proved Reserve Data:					
Total proved reserves (Mmcfe) (4)	189,254	151,750	187,238	275,193	313,866
Pre-tax net present value (discounted 10%)	$ 257,283	$ 166,228	$ 249,406	$ 796,871	987,213
Standardized measure (4)	$ 255,907	$ 166,228	$ 249,406	$ 648,016	771,443

(1) The increase in natural gas and oil sales for the year ended December 31, 2017 is primarily attributable to higher commodity prices during the year. The decrease in natural gas and oil sales for the year ended December 31, 2016 is attributable to lower commodity prices during the year and lower production resulting from the significant reduction in our capital program. The decrease in natural gas and oil sales for the year ended December 31, 2015 is attributable to the decline in commodity prices during the fourth quarter of 2014 and during 2015, combined with lower production as a result of a reduction in our 2015 drilling program. The increase in natural gas and oil sales for the year ended December 31, 2014 is attributable to the Merger with Crimson and new production from our 2013 and 2014 drilling program.

Table of Contents

(2) During the year ended December 31, 2017, we recognized approximately $0.3 million for impairment of proved properties, related to revised estimated reserves for our TMS properties. Additionally, we recognized $1.5 million related the partial impairment of two unused offshore platforms in onshore storage.

During the year ended December 31, 2016, we recognized approximately $0.7 million for impairment of proved properties, substantially all of which was directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from the associated reserves. Additionally, we recognized $6.8 million related to our unproved properties in Fayette and Gonzales counties Texas and $2.9 million related to our unproved acreage in Natrona County, Wyoming.

During the year ended December 31, 2015, we recognized approximately $269.6 million for impairment of proved properties, substantially all of which was directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from the associated reserves. Additionally, we recognized approximately $16.3 million for impairment and partial impairment of certain unproved properties and onshore prospects primarily due to the sustained low commodity price environment and expiring leases.

During the year ended December 31, 2014, we reached a total depth on our Ship Shoal 255 well, and no hydrocarbons were found. As a result, we recognized $31.5 million in exploration expense for the cost of drilling the well and $15.6 million in impairment expense, including $3.5 million related to leasehold costs and $12.1 million related to the platform located in Ship Shoal 263 block which was expected to be used by the Ship Shoal 255 had it been successful. Additionally, during the year ended December 31, 2014, we revised estimated proved reserves for South Timbalier 17 and our TMS properties, resulting in non-cash impairment expenses of approximately $11.4 million. During the year ended December 31, 2014, we also recognized impairment expense of approximately $20.1 million related to full or partial impairment of certain unproved properties due to expiring leases and leases not likely to be drilled.

(3) The increase in the deficit in working capital for the years ended December 31, 2017 and 2016 was primarily related to our activity in West Texas, beginning in the fourth quarter of 2016. The decrease in the deficit in working capital during 2015 was a result of the decrease in drilling activity and the satisfaction of trade obligations existing at the beginning of the year, which were attributable to a more active 2014 drilling program. The increase in the working capital deficit for the year ended December 31, 2014 was primarily attributable to the higher trade obligations associated with the drilling program in late 2014 and a decrease in trade receivables associated with the decline in commodity prices during the fourth quarter of 2014. On October 1, 2013, in connection with the Merger, we entered into a revolving credit facility with Royal Bank of Canada and other lenders.

(4) During the year ended December 31, 2017, our proved reserves increased by approximately 37.5 Bcfe and our standardized measure increased by approximately $89.7 million. This increase is primarily due to 63.1 Bcfe of additions and extensions related to our assets in West Texas and a 9.9 Bcfe positive revision of reserve estimates due to higher commodity prices, partially offset by 20.1 Bcfe in 2017 production and a 12.2 Bcfe decrease due a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded.

During the year ended December 31, 2016, our proved reserves decreased by approximately 35.5 Bcfe and our standardized measure decreased by approximately $83.2 million. This decrease is primarily due to 26.0 Bcfe of production, an 8.3 Bcfe negative revision of reserve estimates due to low commodity prices and 4.2 Bcfe due to the sale of our Colorado properties, partially offset by 2.5 Bcfe related to positive performance revisions.

During the year ended December 31, 2015, our proved reserves decreased by approximately 88.0 Bcfe and our standardized measure decreased by approximately $398.6 million. This decrease is primarily attributable to 2015 production and to the impact of the dramatic decline in commodity prices on the value and volume of our proved reserves and in part to the impact of the significant reduction in our capital spending in response to the low and uncertain commodity price environment.

During the year ended December 31, 2014, our proved reserves decreased by approximately 38.7 Bcfe and our standardized measure decreased by approximately $123.4 million. This decrease is primarily attributable to 40.3 Bcfe of production and a 22.4 Bcfe negative revision of proved developed producing reserves at our Eugene Island 11 field due to a change in forecasted condensate yield and ultimate field abandonment pressure; these decreases were partially offset by 36.1 Bcfe for extensions and discoveries.

During the year ended December 31, 2013, our proved reserves increased by approximately 92.8 Bcfe and our standardized measure increased by approximately $383.4 million, primarily as a result of our Merger with Crimson. Also contributing to the increase was the exercise of our preferential right to purchase approximately 17.0 Bcfe related to our five Contango-operated Dutch wells, slightly offset by 28.2 Bcfe of production, a 19.2 Bcfe decrease in our Dutch and Mary Rose reserve estimates based upon additional pressure data, and a 2.5 Bcfe decrease in our Vermilion 170 reserve estimates, as determined by our reservoir engineer.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this report.

Overview

We are a Houston, Texas based independent oil and natural gas company. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico (“GOM”) and onshore Texas and Wyoming properties and to use that cash flow to explore, develop, exploit, produce and acquire crude oil and natural gas properties in the onshore Texas and Rocky Mountain regions of the United States.

Table of Contents

On October 1, 2013, we completed a merger with Crimson Exploration Inc. (“Crimson”) (the “Merger”). We have historically focused our operations in the GOM, but the Merger gave us access to high rate of return onshore prospects in known, prolific producing areas as well as long-life resource plays. In 2015, prior to the decline in crude oil and natural gas prices, our drilling activity focused primarily on the Woodbine oil and liquids-rich play in Madison and Grimes counties, Texas (our Southeast Texas Region), in the Cretaceous Sands in Fayette and Gonzales counties, Texas (our South Texas Region) and Wyoming where we were targeting the Mowry Shale and the Muddy Sandstone formations. Beginning in the second half of 2015, we reduced our drilling program in response to the challenging commodity price environment. As a result, until the latter half of 2016, our only drilling activity was in Weston County, Wyoming, where we completed our third well targeting the Muddy Sandstone formation. During the third quarter of 2016, we acquired a 12,100 operated gross acre position (5,000 net) in the Southern Delaware Basin in Pecos County, Texas, (the “Acquisition”) and as of December 31, 2017, had increased our acreage in the Southern Delaware Basin to 16,500 gross acres (6,800 net). Since the Acquisition, we have begun production from seven wells in the Southern Delaware Basin and are waiting on completion of an eighth well. We currently expect that the Southern Delaware Basin position will continue to be the primary focus of our drilling program for 2018.

Additionally, we have (i) a 37% equity investment in Exaro Energy III LLC (“Exaro”), which is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; (ii) operated properties producing from various conventional formations in various counties along the Texas Gulf Coast; and (iii) operated producing properties in the Haynesville Shale, Mid Bossier and James Lime formations in East Texas. Until their sale in December 2016, we also had operated producing properties in the Denver Julesburg Basin (“DJ Basin”) in Weld and Adams counties in Colorado.

Our production for the year ended December 31, 2017 was approximately 20.1 Bcfe (or 55.1 Mmcfe/d) and was 68% offshore and 32% onshore. Our production for the three months ended December 31, 2017 was approximately 4.8 Bcfe (or 51.8 Mmcfe/d) and was 66% offshore and 34% onshore. As of December 31, 2017, our proved reserves were approximately 40% offshore and 60% onshore and were 65% proved developed, which were approximately 61% offshore and 39% onshore.

Revenues and Profitability

Our revenues, profitability and future growth depend substantially on our ability to find, develop and acquire natural gas and oil reserves that are economically recoverable, as well as prevailing prices for natural gas and oil.

Reserve Replacement

Generally, producing properties offshore in the Gulf of Mexico have high initial production rates, followed by steep declines. Likewise, initial production rates on new wells in the onshore resource plays start out at a relatively high rate with a decline curve which results in 60% to 70% of the ultimate recovery of present value occurring in the first eighteen months of the well’s life. We must locate and develop, or acquire, new natural gas and oil reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and/or acquire natural gas and oil reserves. A prolonged period of depressed commodity prices could have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes in our development plans. The Merger with Crimson allowed the Company to add significant proved developed and undeveloped reserves and provided the Company with access to several onshore resource plays which have substantial reserve growth potential, including in oil and liquids rich plays that position us to move to a more balanced oil/gas profile.

Use of Estimates

The preparation of our financial statements requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include estimates of remaining proved natural gas and oil reserves, the timing and costs of our future drilling, development and abandonment activities, and income taxes.

See “Item 1A. Risk Factors” for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations.

Table of Contents

Results of Operations

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

	Three Months Ended							
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017
fshore DM tch and ary se (1)	45.9	43.3	39.3	39.5	35.4	36.3	32.2	30.8
rmilion 0 (2)	6.5	6.2	4.0	4.9	4.6	3.1	4.2	3.5
uth mbalier (3)	0.6	0.6	0.6	0.6	0.5	0.2	0.1	—
utheast xas (4)	16.4	13.9	12.1	10.1	8.6	8.2	7.8	7.5
uth xas (5)	7.4	7.4	7.5	7.5	6.4	5.6	4.6	5.8
est xas	—	—	—	—	0.6	3.3	3.2	3.2
her (6)	2.6	3.2	2.2	1.7	1.5	1.3	1.1	1.0
	79.4	74.6	65.7	64.3	57.6	58.0	53.2	51.8

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

Table of Contents

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016; and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2017, 2016 and 2015. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six Mcf of natural gas. Reported operating expenses include production taxes, such as ad valorem and severance.

	Year Ended December 31,			Year Ended December 31,		
	2017	2016	%	2016	2015	%
Revenues (thousands):						
Oil and condensate sales	$ 25,347	$ 23,006	10 %	$ 23,006	$ 43,230	(47) %
Natural gas sales	41,317	43,847	(6) %	43,847	59,058	(26) %
NGL sales	11,881	11,330	5 %	11,330	14,217	(20) %
Total revenues	$ 78,545	$ 78,183	— %	$ 78,183	$ 116,505	(33) %
Production:						
Oil and condensate (thousand barrels)						
Dutch and Mary Rose	89	120	(26) %	120	164	(27) %
Vermilion 170	10	16	(38) %	16	22	(27) %
Southeast Texas	151	239	(37) %	239	493	(52) %
South Texas	95	128	(26) %	128	178	(28) %
West Texas	133	—	100 %	—	—	— %
Other	40	94	(57) %	94	67	40 %
Total oil and condensate	518	597	(13) %	597	924	(35) %
Natural gas (million cubic feet)						
Dutch and Mary Rose	9,891	12,375	(20) %	12,375	14,736	(16) %
Vermilion 170	1,222	1,616	(24) %	1,616	2,050	(21) %
Southeast Texas	1,328	2,059	(36) %	2,059	3,136	(34) %
South Texas	1,112	1,528	(27) %	1,528	1,788	(15) %
West Texas	82	—	100 %	—	—	— %
Other	275	525	(48) %	525	904	(42) %
Total natural gas	13,910	18,103	(23) %	18,103	22,614	(20) %
Natural gas liquids (thousand barrels)						
Dutch and Mary Rose	310	378	(18) %	378	454	(17) %
Vermilion 170	20	42	(52) %	42	60	(30) %
Southeast Texas	115	217	(47) %	217	359	(40) %
South Texas	60	72	(17) %	72	87	(17) %
West Texas	12	—	100 %	—	—	— %
Other	—	7	(100) %	7	8	(13) %
Total natural gas liquids	517	716	(28) %	716	968	(26) %
Total (million cubic feet equivalent)						
Dutch and Mary Rose	12,283	15,364	(20) %	15,364	18,443	(17) %
Vermilion 170	1,402	1,965	(29) %	1,965	2,545	(23) %

Southeast Texas	2,924	4,792	(39) %	4,792	8,249	(42) %
South Texas	2,038	2,729	(25) %	2,729	3,379	(19) %
West Texas	947	—	100 %	—	—	— %
Other	529	1,132	(53) %	1,132	1,345	(16) %
Total production	20,123	25,982	(23) %	25,982	33,961	(23) %

	Year Ended December 31,				Year Ended December 31,			
	2017	2016	%		2016	2015	%	
Daily Production:								
Oil and condensate (thousand barrels per day)								
Dutch and Mary Rose	0.2	0.3	(26)	%	0.3	0.4	(27)	%
Vermilion 170	—	—	(38)	%	—	0.1	(27)	%
Southeast Texas	0.4	0.7	(37)	%	0.7	1.4	(52)	%
South Texas	0.3	0.4	(26)	%	0.4	0.5	(28)	%
West Texas	0.4	—	100	%	—	—	—	%
Other	0.1	0.2	(57)	%	0.2	0.1	40	%
Total oil and condensate	1.4	1.6	(13)	%	1.6	2.5	(35)	%
Natural gas (million cubic feet per day)								
Dutch and Mary Rose	27.1	33.8	(20)	%	33.8	40.4	(16)	%
Vermilion 170	3.3	4.4	(24)	%	4.4	5.6	(21)	%
Southeast Texas	3.6	5.6	(36)	%	5.6	8.6	(34)	%
South Texas	3.0	4.2	(27)	%	4.2	4.9	(15)	%
West Texas	0.2	—	100	%	—	—	—	%
Other	0.9	1.5	(48)	%	1.5	2.4	(42)	%
Total natural gas	38.1	49.5	(23)					