CONTANGO OIL & GAS CO
Form 10-K
March 18, 2019

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, 2018

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 every Interactive Data File required to be submitted 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 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	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 29, 2018, 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 $112.0 million. As of March 11, 2019, there were 34,465,980 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.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

- our ability to continue as a going concern;
- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin and realize the benefits associated therewith;
- our financial position;
- our business strategy, including execution of any changes in our strategy;
- meeting our forecasts and budgets, including our 2019 capital expenditure budget;
- expectations regarding natural gas and oil markets in the United States;
- volatility in natural gas, natural gas liquids and oil prices, including regional differentials;
- 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;
- our ability to comply with financial covenants in our debt instruments, repay indebtedness and access new sources of indebtedness;
- 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;
- our ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- our ability to complete strategic dispositions or acquisitions of assets or businesses and realize the benefits of such dispositions or acquisitions;
- 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;
  - 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;
- the ability to obtain adequate insurance coverage on commercially reasonable terms; and
- the limited trading volume of our common stock and general market volatility.

Any of these factors and other factors described in this report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable when made, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. You should not place undue reliance on forward-looking statements in this report as they 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.

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

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

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PART I

Item 1. Business

Overview

We are a Houston, Texas based independent 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 West Texas, the onshore Texas Gulf Coast and the Rocky Mountain regions of the United States. We were formed in 1999 as a Nevada corporation and changed our state of incorporation to Delaware in 2000.

The following table lists our primary producing areas as of December 31, 2018:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Southern Delaware Basin, Pecos County, Texas	Wolfcamp
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Eagle Ford / Georgetown
San Augustine County, Texas	Haynesville shale, Mid Bossier shale and James Lime formations
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 2016, we have been focused on the development of our Southern Delaware Basin acreage in Pecos County, Texas ("Bullseye"). As of December 31, 2018, we were producing from twelve wells over our 15,400 gross (6,500 net) acre position, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. In December 2018, we purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of our existing acreage ("NE Bullseye") for approximately $7.5 million. We paid $3.2 million cash in December 2018, with the balance to be paid by the earlier of the commencement of completion operations on the third well on the acreage acquired or October 1, 2019. We currently expect that Bullseye and NE Bullseye will be the primary focus of our drilling program for 2019. During this period, we will continue to identify opportunities for cost reductions and operating efficiencies in all areas of our operations, while also searching for new resource acquisition opportunities.

As we continue to expand our presence in the Southern Delaware Basin, we have begun to sell non-core assets to allow us to focus on West Texas. These asset sales provide some immediate liquidity and improve our balance sheet by removing potential asset retirement obligations. Beginning in 2016, we sold all of our Colorado assets for approximately $5.0 million. During the year ended 2018, we sold certain Eagle Ford Shale assets in Karnes County, Texas for $21.0 million; Gulf Coast conventional assets in Southeast Texas for $6.0 million, and Gulf Coast conventional and unconventional assets in South Texas for $0.9 million. In December 2018, we also sold our offshore Vermilion 170 property in exchange for a retained overriding royalty interest ("ORRI") in the well, the buyer's assumption of the plugging and abandonment obligation and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through this platform.

In July 2016, 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 Bullseye and provide funding for the costs associated with drilling our initial wells in the Southern Delaware Basin.

In November 2018, we completed an underwritten public offering of 8,596,068 shares of our common stock for net proceeds of approximately $33.0 million, which were used to reduce borrowings under our Credit Facility, fund the initial purchase of the NE Bullseye acreage and provide funding for our 2019 capital expenditure program.

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Our production for the year ended December 31, 2018 was approximately 16.0 Bcfe (or 43.9 Mmcfe/d) and was comprised of 62% from our offshore properties and 61% natural gas. Our production for the three months ended December 31, 2018 was approximately 3.7 Bcfe (or 39.8 Mmcfe/d), with 63% from our offshore properties and 58% natural gas. As of December 31, 2018, our proved reserves were approximately 60% proved developed, were 38% offshore, were 41% natural gas and were 99% attributed to wells and properties operated by us.

As of December 31, 2018, 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 131.9 Bcfe, consisting of 54.2 Bcf of natural gas, 9.4 MMBbl of crude oil and condensate and 3.5 MMBbl of natural gas liquids ("NGLs"), with a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $218.9 million and a present value, discounted at a 10% rate based on year-end SEC pricing guidelines (PV 10), of $220.5 million. PV-10 as of December 31, 2018 was based on adjusted prices of $3.02 per MMbtu of natural gas, $62.90 per barrel of oil, and $27.89 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, 2018 (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, 2018:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	Natural % Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Offshore GOM	49.5	3 %	80 %	17 %	100 %	27.0
Southeast Texas	16.1	57 %	24 %	19 %	50 %	5.9
South Texas	5.4	24 %	56 %	20 %	89 %	3.8
West Texas	59.0	72 %	13 %	15 %	27 %	6.3
Other (1)	1.9	98 %	2 %	— %	60 %	0.9
Total	131.9					43.9

(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 equity method investment in Exaro, as of December 31, 2018, 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, 2018:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Investment in Exaro	26.6	6 %	94 %	— %	100 %	21.6

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, and while we have sufficient sources of capital, 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 either 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

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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 may acquire individual properties or private or publicly traded companies, in each case for cash, common stock, preferred stock or combination thereof. We believe that the ongoing low commodity price environment might provide growth opportunities for us through potential corporate combinations that provide a combination of producing properties and undeveloped growth potential.

• 2019 business strategy. While we review liquidity-enhancing alternative sources of capital, we intend to continue to minimize our drilling program capital expenditures in the Southern Delaware Basin and pursue a reduction in our borrowings under our Credit Facility, including through a reduction in cash, general and administrative expenses and the possible sale of additional non-core properties. We currently expect to focus our 2019 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. 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 2019 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 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 2019 capital expenditure budget is currently estimated at $30.3 million and is expected to include the following:

· Southern Delaware Basin (Bullseye) – $8.1 million to drill and complete the American Hornet #1H and to complete the Ripper State #2H which was drilled in 2018.

· Southern Delaware Basin (NE Bullseye) – $13.5 million to drill and complete three wells in this newly acquired acreage.

· Southern Delaware Basin – $1.3 million in additional leasehold, extension and title costs plus $5.5 million in infrastructure costs, primarily water and gas gathering facilities in NE Bullseye.

· Other – $1.9 million to participate in two non-operated wells targeting the Georgetown formation in our South Texas area.

Properties

Offshore Gulf of Mexico

As of December 31, 2018, our offshore assets consisted of five producing federal and two producing state of Louisiana company-operated wells in the shallow waters of the GOM. The following summary table sets forth certain information with respect to our offshore reserves as of December 31, 2018 and average daily offshore production for the year ended December 31, 2018:

Field	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Dutch and Mary Rose	49.4	2 %	80 %	18 %	100 %	24.8
Vermilion 170 (1)	0.1	4 %	86 %	10 %	100 %	2.2
Total	49.5					27.0

(1) These reserves are attributable to our 8.7% override royalty interest after the sale of this property effective December 1, 2018.

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Dutch and Mary Rose Field

We currently operate five producing wells located in federal waters at Eugene Island 10 (“Dutch”), and two producing wells located in adjacent Louisiana state waters (“Mary Rose”). We plugged and abandoned the Mary Rose #4 well in 2018. We expect to plug the Mary Rose #5 well in early 2019 and the Mary Rose #3 well in 2020. 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 oil and natural gas markets thereby minimizing downtime risk and providing the ability to select the best sales price for our oil and 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 southwest of Abbeville, Louisiana and oil can flow via a 6” oil pipeline to third-party owned and operated onshore processing facilities in St. Mary Parish, Louisiana. Production facilities include a turbine type compressor capable of servicing all Dutch and Mary Rose wells at the Eugene Island 11 platform. Condensate can also flow to onshore markets and multiple refineries.

Vermilion 170 Field

For most of 2018, we owned and operated one well located in federal waters with a dedicated production facility at Vermilion 170. Production from this platform flows via the Sea Robin Pipeline to a third-party owned and operated onshore processing plant. Effective December 1, 2018, this well was sold to a third-party independent oil and gas company in exchange for the buyer’s assumption of the plugging and abandonment liability for the Vermilion 170 well, platform and associated pipeline, an ORRI in the Vermilion 170 well and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through the Vermilion 170 platform if successful.

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 and South Timbalier wells were permanently plugged and abandoned, and the production facilities were removed and sold.

Onshore Properties

Southern Delaware Basin

Since July 2016, we and our 50% working interest partner in the Southern Delaware Basin have increased our leasehold footprint from approximately 5,000 undeveloped acres, net to Contango, to approximately 8,400 acres, net to Contango. As of December 31, 2018, we estimate that we have proved reserves of 59.0 Bcfe (72% oil, 87% total liquids). We believe substantially all of the potential drilling locations on this acreage can accommodate 10,000 foot laterals.

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Our first five Southern Delaware Basin wells in Pecos County, Texas were brought on production during 2017 at an average 30-day initial daily production (“IP 30”) rate of 852 Boed, of which was approximately 71% oil on an equivalent basis. During the year ended December 31, 2018, we brought seven additional wells on production as follows:

Well Name	Formation	First Production	IP 30 (BOED)	% Oil	WI %	NRI %	TMD (feet)	Lateral (feet)
Ragin Bull 3H	Wolfcamp A	Jan 2018	1,070	67 %	49 %	37 %	20,570	10,325
River Rattler 1H	Wolfcamp B	March 2018	1,225	74 %	44 %	33 %	20,710	10,275
Ragin Bull 2H	Wolfcamp B	April 2018	734	66 %	49 %	37 %	20,625	10,334
Sidewinder 1H	Wolfcamp A	July 2018	368	70 %	49 %	37 %	20,550	10,500
Gunner 3H	Wolfcamp B	July 2018	773	78 %	47 %	35 %	20,167	10,067
Fighting Ace 2H	Wolfcamp A	Sept 2018	656	71 %	50 %	38 %	20,560	10,598
General Paxton 1H	Wolfcamp A	Oct 2018	981	79 %	50 %	38 %	20,145	10,392

As of December 31, 2018, we had nine wells producing from the Wolfcamp A, three wells producing from the Wolfcamp B, and a fourth well drilled in the Wolfcamp B that will be completed later in 2019.

Southeast Texas

As of December 31, 2018, our Southeast Texas region included approximately 20,000 gross (12,100 net) acres, proved reserves of 16.1 Bcfe and 50 gross (30.8 net) producing wells. In November 2018 we sold non-core conventional assets located in Liberty and Hardin counties for approximately $6.0 million. The average net daily production of these sold properties was 2.1 Mmcfe/d for the year ended December 31, 2018. 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. No drilling capital has been allocated to this area since 2015 due to the low commodity price environment and our focus on our Southern Delaware position.

South Texas

As of December 31, 2018, our South Texas region included approximately 56,400 gross (29,300 net) acres, proved reserves of 5.4 Bcfe and 65 gross (32.2 net) producing wells. In the Dimmitt and Zavala counties part of this region, we believe approximately 15,700 gross (7,100 net) acres to be prospective for the Buda, Georgetown and Eagle Ford Shale plays. Our estimated net proven Buda/Eagle Ford/Georgetown reserves in this area were 1.8 Bcfe, comprised of 73% liquids, with 27 gross (11.7 net) producing wells, as of December 31, 2018. No drilling activity has been conducted in this area since 2014 due to the reduction in our capital expenditure programs in response to the commodity price environment, with the exception of two successful non-operated Georgetown wells in which we participated in drilling in 2017 and 2018. Of the proved reserves in this area, our estimated net proved reserves related to these two drilled wells is 0.6 Bcfe, as of December 31, 2018. For 2019, we currently plan to participate in two more non-operated Georgetown wells in Dimmitt County, and should we experience sustained improvement in commodity prices, we could increase our activity in pursuit of the Georgetown in this area.

Our South Texas region also includes approximately 40,700 gross (22,200 net) acres located in conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved conventional reserves in this region were 2.9 Bcfe, comprised of 71% gas, with 22 gross (9.7 net) producing wells, as of December 31, 2018.

During 2018, we sold non-core conventional assets located in South Texas for approximately $0.9 million. The average net daily production of these sold properties was 1.4 Mmcfe/d for the year ended December 31, 2018.

Weston County, Wyoming

In 2015, we drilled the first of three successful wells in this area targeting the Muddy Sandstone formation. As a result of drilling these wells, we have satisfied the right to earn 35,000 net acres, of which approximately 70% will expire over the next three years if no drilling activity is conducted. 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. Approximately 4% of our acreage is held by production.

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Other (East Texas)

As of December 31, 2018, our East Texas region included approximately 5,900 gross (3,600 net) acres primarily in San Augustine County, with proved reserves of 0.5 Bcfe comprised of 78% 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 2019. As of December 31, 2018, substantially all of our acreage in our East Texas region was held by production.

Other

As of December 31, 2018, we held approximately 2,100 gross (500 net) mostly undeveloped acres in Louisiana, and Mississippi.

Impairment of Long-Lived Assets

We recognized $103.2 million in non-cash impairment charges in 2018, substantially all of which related to proved properties. Under US GAAP, an impairment charge is required when the unamortized capital cost of any individual property within the Company’s 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 charges incurred in 2018 was $61.7 million related to the impairment of the carrying costs of our proved offshore Gulf of Mexico properties made during the quarter ended September 30, 2018. This impairment was primarily a result of revised proved reserve estimates based on new bottom hole pressure data gathered during the planned installation of a second stage of compression in our Eugene Island 11 field. In 2018, we also recognized onshore proved property impairment expense of $40.2 million, of which $24.9 million was related to certain of our non-core properties in South and Southeast Texas that were reduced to their fair value as a result of planned sales during the quarters ended September 30, 2018 and December 31, 2018, and $15.3 million of impairment was due to price related reserve revisions primarily on our Wyoming and certain South Texas assets. In 2018, the Company recognized impairment expense of approximately $1.3 million related to unproved properties due to expiring leases.

If oil or natural gas prices decline from those prices at December 31, 2018, 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, 2018, we had invested approximately $46.9 million in Exaro, with no requirement to make 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, 2018, Exaro had 648 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 22 Mmcfe/d, net to Exaro. For the year ended December 31, 2018, the Company recognized a net investment loss of approximately $12.6 million, net of zero tax expense, as a result of its investment in Exaro. As of December 31, 2018, reserves attributable to our investment in Exaro were 26.6 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,

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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 Credit Facility. These mortgages and the related Credit Facility contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 12 to our Financial Statements "Indebtedness" 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.

As of December 31, 2018, we had the following derivative contracts in place:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	Jan 2019 - March 2019	Swap	600,000 MMBtus	$ 3.21 (1)
Natural Gas	April 2019 - July 2019	Swap	600,000 MMBtus	$ 2.75 (1)
Natural Gas	Aug 2019 - Oct 2019	Swap	100,000 MMBtus	$ 2.75 (1)
Natural Gas	Nov 2019 - Dec 2019	Swap	500,000 MMBtus	$ 2.75 (1)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$ 52.00 - 59.45 (3)
Oil	Jan 2019 - June 2019	Collar	12,000 Bbls	$ 70.00 - 76.25 (3)
Oil	Jan 2019 - July 2019	Swap	6,000 Bbls	$ 66.10 (3)
Oil	July 2019	Swap	12,000 Bbls	$ 72.10 (3)
Oil	Aug 2019 - Oct 2019	Swap	9,000 Bbls	$ 72.10 (3)
Oil	Nov 2019 - Dec 2019	Swap	12,000 Bbls	$ 72.10 (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.

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- Political conditions in the Middle East and other natural gas and oil producing regions.
- The level of LNG imports/exports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- The loss of tax credits and deductions.

Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. The largest purchaser of our production for the year ended December 31, 2018, calculated on an equivalent basis, was ConocoPhillips Company (36.9%). 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.

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

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

Regulation of Sales and Transportation of Natural Gas

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

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

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FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704 as clarified in orders on clarification and rehearing. In addition, to the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC's regulations could result in the imposition of civil and criminal penalties.

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

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the 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, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays, cancellations or restrictions in permitting or performance of projects and the issuance of orders enjoining some or all of our operations in affected areas. The public continues to have a significant interest in the protection of the environment. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment, and thus any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly exploration, production and development activities, or waste handling, storage transport, disposal or remediation requirements could result in increased costs of our doing business and consequently affect our profitability. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

The federal 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 or natural resource 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. 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 federal Clean Air Act, as amended (the “CAA”), and comparable state laws restrict the emission of air pollutants from many sources and also impose various pre-construction, operating, 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.

There remains continued public, governmental and scientific attention regarding climate change, with the EPA having determined that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment. As a result, the EPA has 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, delay or halt our

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ability to obtain air permits for new or modified sources. Additionally, 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 annually 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 include consideration of cap-and-trade programs whereby major sources of GHG emissions are required to acquire and surrender emission allowances in return for emitting those GHGs, as well as carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Internationally, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by the United States in April 2016, requires countries to review and “represent a progression” in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. In June 2017, the Trump administration announced its intention for the United States to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the earliest date the United States can withdraw is November 2020. 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. The EPA and the U.S. Army Corps of Engineers released a rule to revise the definition of “waters of the United States,” or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. The EPA has instituted rulemakings to both delay the effective date of this rule and repeal the rule. Federal district court decisions have preserved the stay in a majority of states, which remain subject to pre-2015 regulated waters regulations, whereas the stay has been enjoined in a minority of states. Litigation surrounding this rule is ongoing. More recently, on December 11, 2018, the EPA and the Corps released a proposal to revise the 2015 Clean Water Rule so as to narrow the regulatory definition of waters of the United States; the revised rule has not yet been finalized.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended (the “SDWA”), and analogous state laws. 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, and thus, those activities are subject to the SWDA. 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 and natural resource 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 federal Oil Pollution Act of 1990, as amended (the “OPA”), and regulations thereunder impose a variety of regulations on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA applies to vessels, onshore facilities and offshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities and lessees and permittees of offshore leases may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. In January 2018, the federal Bureau of Ocean Energy Management (“BOEM”) raised the OPA’s damages liability cap to $137.7 million; however, 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. The 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. The 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 our offshore lease operations affect state waters, we 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. 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. 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 restrictions, delays or cancellations in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

The National Environmental Policy Act, as amended (“NEPA”) is applicable to oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM. 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.

The federal Endangered Species Act, as amended ("ESA"), provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits taking of endangered species. The ESA may impact exploration, development and production activities on public or private lands. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act, as amended. 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 as well as time delays or limitations on or cancellations of our drilling program activities, which costs, delays, limitations or cancellations 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.

The BOEM and the BSEE, each agencies of the U.S. Department of the Interior, have, over time, imposed more stringent permitting procedures and regulatory safety and performance requirements for wells in federal waters. For example, in 2016, the BOEM issued a Notice to Lessees and Operators (the "NTL #2016-N01") that became effective in September 2016 and bolsters supplemental financial assurance requirements for the decommissioning of offshore wells, platforms, pipelines and other facilities whereas the BSEE has issued various regulations relating to the safe and environmentally responsible development of energy and mineral resources on the OCS that have resulted in more stringent requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. Additionally, 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, delay or cancel new drilling and ongoing development efforts. 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. 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 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 that may be adopted or enforced by the BOEM or the BSEE in the future could delay or disrupt our oil and natural gas exploration and production operations conducted offshore, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit or cancel 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, or any subsequent 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, or any subsequent assignee, of offshore facilities is unwilling or unable to perform, we could incur costs to perform decommissioning, 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.

See “Item 1A. Risk Factors” for further discussion on hydraulic fracturing; ozone standards; climate change, including methane or other GHG emissions; releases of regulated substances; offshore regulatory safety and environmental development requirements, and other aspects of compliance with legal or financial assurance requirements or relating to environmental protection, including with respect to offshore leases. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards or more stringent enforcement programs continue to evolve.

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 offshore tracts on 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. In June 2017, the BOEM extended indefinitely the start date for implementation of NTL #2016-N01. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder’s decommissioning obligations.

The BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the BOEM determines whether and to what extent any additional financial assurance may be required by us with respect to our offshore operations, 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. See “Item 1A. Risk Factors” for a further discussion on BOEM and its implementation of NTL #2016-N01.

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 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 result in the assessment of civil penalties and/or require a shut-in of our Gulf of Mexico operations if not resolved within the required time.

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Employees

On December 31, 2018, we had 46 full time employees, of which 11 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, 2021. Rent, including parking, related to this office space for the year ended December 31, 2018 was approximately $2.5 million. A portion of our space in the building is being subleased through March 31, 2019 for approximately $50 thousand per month.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. 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 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. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this report.

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, as well as all other information presented in this Form 10-K. An investment in the Company is subject to risks inherent in our business, and the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, results of operations and financial condition in the future. 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.

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, NGL and crude oil prices. Natural gas prices, NGL prices and crude oil prices remained relatively low through the first half of 2018. During the final months of 2018, natural gas, NGLs and crude oil prices showed temporary periods of improvement, before weakening during the latter half of December and in to January 2019. The markets for these commodities are volatile

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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, NGLs 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, and alternative fuels.
- 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.

A substantial or extended decline in natural gas, NGL and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas, NGLs 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, and a reduction in our drilling program may affect our revenues and access to capital.

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 NGL price declines. 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.

Additionally, we intend to continue to minimize our drilling program capital expenditures and currently expect that Bullseye and NE Bullseye will be the primary focus of our drilling program for 2019. Any reduction in our drilling program will adversely affect our future production levels and future cash flow generated from operations. Furthermore, to the extent we are unable to execute our expected drilling program, our return on investment may not be as attractive as we anticipate, and our common stock price may decrease.

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.

We may not be able to refinance or replace our maturing debt on favorable terms, or at all, which will materially adversely affect our financial condition and our ability to develop our oil and gas assets.

Our Credit Facility, which consists of substantially all of our funded debt matures on October 1, 2019, and under the Sixth Amendment to the Credit Facility (the "Sixth Amendment"), the current borrowing base was reduced on and after January 31, 2019, as further discussed below. As of December 31, 2018, we had $60.0 million outstanding under our Credit Facility, which matures on October 1, 2019. We have been involved in discussions with our current lenders and other sources of capital regarding alternatives that would include the replacement or refinancing of the Credit Facility, which matures on October 1, 2019. There is no assurance, however, that such discussions will result in a refinancing of the Credit Facility on acceptable terms, if at all or provide any specific amount of additional liquidity for future capital expenditures, and in such case there is substantial doubt that the Company could continue as a going concern. The consolidated financial statements included in this report have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets and satisfaction of liabilities and commitments in the normal course of business. The financial statements do not include adjustments that might result from the outcome of the uncertainty, including any adjustments to reflect the possible future effects of the recoverability and classification of recorded asset amounts or amounts and classifications of liabilities that might be necessary should we be unable to continue as a going concern. Alternative sources of capital could involve the issuance of debt or equity on unfavorable terms or that would result in significant dilution. While we review such liquidity-enhancing alternative sources of capital, we intend to continue to minimize our drilling program capital expenditures in the Southern Delaware Basin and pursue a reduction in our borrowings under the Credit Facility, including through a reduction in cash general and administrative expenses and the possible sale of additional non-core properties. In the absence of such a transaction, we may have to continue to be less aggressive in our drilling program, sell core and non-core assets, and further reduce general and administrative expenses in order to pay down outstanding debt under the Credit Facility, or a combination of the foregoing. These transactions or actions could have a material adverse effect on our financial condition and results of operations and the trading price of our common stock.

If we are unable to comply with restrictions and covenants in our Credit Facility, there could be a default under the terms of the agreement, which could result in an acceleration of payments of funds that we have borrowed.

We have faced challenges meeting certain financial performance covenants under our Credit Facility. The Credit Facility contains restrictive covenants which, among other things, restricts the declaration or payment of dividends by us, prevents the repurchase of shares and requires a Current Ratio of at least 1.00 to 1.00 and a Leverage Ratio of not more than 3.50 to 1.00, both as defined in the Credit Facility agreement. As of December 31, 2018, we were in compliance with all financial covenants under the Credit Facility agreement. However, we were not in compliance with the Current Ratio covenant as of September 30, 2018 and obtained a waiver for such non-compliance, if any, for the quarters ending September 30, 2018 and December 31, 2018. In the future, we may be required to seek further waivers and modifications of covenants, or to further reduce our debt by, among other things, reducing our bank borrowing base, issuing equity or completing asset sales and other liquidity-enhancing activities, and these efforts may not be successful. We cannot assure you, however, that we will be able to successfully modify these covenants or obtain waiver for non-compliance or reduce our debt in the future. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the Credit Facility or other agreements governing our indebtedness, an event of default could result, which could permit acceleration of such debt and acceleration of our other debt. Any accelerated debt would become immediately due and payable.

Our bank borrowing base is adjusted semiannually in May and November of each year, and upon requested unscheduled special redeterminations, in each case at the banks' discretion, and the amount is established and based, in part, upon certain external factors, such as commodity prices. Under the Sixth Amendment, effective November 2, 2018, the borrowing base of $105 million was reaffirmed but the borrowing base was reduced to $90 million at January 31, 2019. This lowering of our borrowing base limits availability under our bank Credit Facility or requires us to seek different forms of financing arrangements, and we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding upon its maturity. If the outstanding debt under our Credit Facility were to ever exceed the borrowing base, we would be required to repay the excess amount within a short period. Such acceleration of indebtedness could require us to pursue strategic restructuring options, which would have a material adverse effect on the trading price of our common stock.

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 Credit Facility and/or proceeds from non-core asset sales and our 2018 underwritten public offering of common stock. 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 Facility contains 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 Credit Facility, we may be unable to obtain financing otherwise currently available under our Credit Facility. As part of the regular redetermination schedule, the borrowing base on our Credit Facility was redetermined at $105 million effective November 2, 2018 and through January 31, 2019, decreasing automatically to $90 million on that date and until the next regular redetermination date of May 01, 2019. 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. 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, including the refinancing of our Credit Facility, 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 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.

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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.

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.

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 a replacement well.

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.

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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 40% of our total estimated proved reserves at December 31, 2018 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, 2018 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2018. For our condensate and natural gas liquids, the average West Texas Intermediate (Cushing) posted price was $65.56 per barrel for offshore and onshore Southern Delaware Basin volumes, as prepared by Cobb, and the average West Texas Intermediate (Plains) posted price was $62.04 per barrel for all other onshore volumes, as prepared by NSAI. For our natural gas, the average Henry Hub spot price was $3.10 per MMBtu for all offshore and onshore volumes, as prepared by both Cobb and NSAI. Assuming strip pricing as of March 1, 2019 through 2023 and keeping pricing flat thereafter, instead of 2018 SEC pricing, while leaving all other parameters unchanged, the Company's proved reserves would have been 84.8 Bcfe and the PV-10 value of proved reserves would have been $145.4 million. Any adjustments to the estimates of proved reserves or decreases in the price

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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;
- 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;

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- 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.

A sustained continuation of product transportation, processing and market constraints in the Southern Delaware Basin may adversely impact our results of operations and the value of our oil and gas properties in the region.

The Permian Basin, which includes the Southern Delaware Basin in which we have significant oil and gas properties, has been subject to significant product transportation and market constraints resulting from the increased drilling activity and consequent increased production of oil, natural gas and natural gas liquids in the region. One of the results of these constraints over the past year is the development of significant negative field pricing differentials for Southern Delaware Basin oil, natural gas and natural gas liquids production when compared to prices at major domestic oil and natural gas product hubs. For example, during the three months ended December 31, 2018, pricing for oil of similar quality quoted for delivery within the Permian Basin at the Midland oil hub has ranged between $5.44 and $14.15 per barrel lower than West Texas Intermediate oil deliveries at the Cushing and Oklahoma oil hub. The 2019 calendar year forward pricing strip for this Midland-Cushing differential on March 11, 2019 was $(0.65). While extensive capital investments are being made to provide additional production transportation, natural gas processing and alternative markets in the region, there is no assurance as to when or if any of these additional midstream and alternative market projects might be made available to our production or at what cost. If these constraints and consequent pricing differentials continue unabated for a significant amount of time, the financial returns for oil and gas assets in the Southern Delaware Basin may be considerably devalued when compared to oil and gas investments in hydrocarbon producing regions with greater access to major hydrocarbon markets.

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.

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- 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.

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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 and price differentials of crude oil, natural gas and natural gas liquids, as well as interest rates, we have, and may in the future, enter into over-the-counter ("OTC") 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 OTC 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 various regulatory requirements will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. In addition, recently, proposals have been made by U.S. banking regulators which, if adopted as proposed, could significantly increase the capital requirements for certain participants in the OTC derivatives market in which we participate. The Dodd-Frank Act and regulations, such as the recently proposed increased capital requirements regulation, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors.

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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.

During the year ended December 31, 2018, we recognized $77.0 million in non-cash impairment charges of proved properties due to reserve revisions. Included in the impairment charges was $61.7 million related to the impairment of the carrying costs of our proved offshore Gulf of Mexico properties made during the quarter ended September 30, 2018. This impairment was primarily a result of revised proved reserve estimates based on new bottom hole pressure data gathered during the planned installation of a second stage of compression in our Eugene Island 11 field. In addition, we recognized onshore proved property impairment expense of $15.3 million due to price related reserve revisions primarily on our Wyoming and certain South Texas assets.

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 2019, 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. An impairment may have a material adverse effect on our financial results and the trading price of our common stock.

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

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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 onshore and offshore oil and natural gas production facilities, which includes certain of our operations.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In 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 expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices. However, in 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years, but the EPA has not yet published a final rule. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. Furthermore, in late 2016, the BLM published a final rule to reduce methane emissions by regulating venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the 2016 final rule and codifies the BLM’s prior approach to venting and flaring, but the rule rescinding the 2016 final rule has been challenged in federal court and remains pending. These rules, should they remain or be placed in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in restrictions, delays or cancellations in such operations, which costs, restrictions, delays or cancellations could adversely affect our business. 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, which devaluation could be significant.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. 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 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.

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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.

We may not be able to utilize a portion of our net operating loss carryforwards ("NOLs") to offset future taxable income for U.S. federal income tax purposes, which could adversely affect our net income and cash flows.

As of December 31, 2018, we had federal net operating loss ("NOL") carryforwards of approximately $380.8 million, approximately $286.3 million of which began to expire in 2018 and will continue to expire in varying amounts through 2037. Utilization of these NOLs depends on many factors, including our future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of an NOL that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). Determining the limitations under Section 382 is technical and highly complex. An ownership change generally occurs if one or more shareholders (or groups of shareholders) who are each deemed to own at least 5% of the corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change occurs with respect to a corporation following its recognition of an NOL, utilization of such NOL is subject to an annual limitation under Section 382, generally determined by multiplying the value of the corporation's stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382. However, this annual limitation would be increased under certain circumstances by recognized built-in gains of the corporation existing at the time of the ownership change. In the case of an NOL that arose in a taxable year beginning before January 1, 2018, any unused annual limitation with respect to an NOL generally may be carried over to later years, subject to the expiration of such NOL 20 years after it arose.

Our stock offering in November 2018, combined with ownership shifts over the rolling three-year period, resulted in an ownership change under Section 382, which limits the Company's future ability to use its NOLs. As such, we are limited in use of NOLs and Section 163(j) interest expense limitations for amounts incurred prior to November 20, 2018 in an amount equal to $2.4 million per year (plus any recognized built in gains during the next five years) or until expiration of each annual vintage of NOL (generally, 20 years for each annual vintage of NOLs incurred prior to 2018). Due to the presence of the valuation allowance from prior years, this event resulted in a no net charge to earnings. Future changes in our stock ownership or future regulatory changes could also limit our ability to utilize our NOLs. To the extent we are not able to offset future taxable income with our NOLs, our net income and cash flows may be adversely affected.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

In recent years, U.S. lawmakers have proposed certain significant changes to U.S. tax laws applicable to oil and natural gas companies. These changes include, but are not limited to: (i) the elimination of current deductions for intangible drilling and development costs; (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these changes were not included in the Tax Cuts and Jobs Act of 2017, it is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes were to be enacted, as well as any similar changes in state law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

We are subject to stringent environmental laws and regulations 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, cancellations 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. We maintain insurance coverage for sudden and accidental environmental damages; however, it is possible that coverage might not be sufficient in a catastrophic event. Consequently, we could be exposed to liabilities for cleanup costs, natural resource damages and other damages under these laws and regulations, with certain of these legal requirements imposing strict liability for such damages and costs, even though the conduct in pursuing operations was lawful at the time it occurred or the conduct resulting in such damage and costs were caused by prior operators or other third-parties.

Environmental laws and regulations in the United States are subject to change in the future, possibly resulting in more stringent legal requirements. If existing environmental regulatory requirements or enforcement policies change or new regulatory or enforcement initiatives are developed and implemented in the future, we may be required to make significant, unanticipated capital and operating expenditures with respect to the continued operations of the drilling program. Examples of recent environmental regulations include the following:

- Ground-Level Ozone Standards. In 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either “attainment/unclassifiable,” unclassifiable” or “non-attainment.” Additionally, in November 2018, the EPA issued final requirements that apply to state, local, and tribal air agencies for implementing these 2015 standards for ground-level ozone. State implementation of these revised standards 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 expenditures and operating costs arising from our operations.
- EPA Review of Drilling Waste Classification. Drilling, fluids, produced water and most of the other wastes associated with the exploration, development and production of oil or natural gas, if properly handled, are currently exempt from regulation as hazardous waste under the RCRA and instead, are regulated under RCRA’s less stringent non-hazardous waste provisions. However, pursuant to a consent decree issued by the U.S. District Court for the District of Columbia in 2016, the EPA is required to propose by no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations that could result in oil and natural gas exploration and production wastes being regulated as hazardous wastes, or sign a determination that revision of the regulations is unnecessary. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021.

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Federal Jurisdiction over Waters of the United States. In 2015, the EPA and U.S. Army Corps of Engineers (“Corps”) released a final rule outlining federal jurisdictional reach under the Federal Water Pollution Control Act, also known as the “Clean Water Act,” over waters of the United States, including wetlands. Beginning in the first quarter of 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, the agencies have (i) published a proposed rule in 2017 to rescind the

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2015 rule and recodify the regulatory text that governed waters of the United States prior to promulgation of the 2015 rule, (ii) published a final rule in February 2018 adding a February 6, 2020 applicable date to the 2015 rule, and (iii) published a proposed rule in December 2018 re-defining the Clean Water Act's jurisdiction over waters of the United States for which the agencies will seek public comment. The 2015 and February 2018 final rules are being challenged by various factions in federal district court and implementation of the 2015 rule has been enjoined in twenty-eight states pending resolution of the various federal district court challenges. As a result of these legal developments, future implementation of the 2015 rule or a revised rule is uncertain at this time. To the extent that the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we conduct operations, we could incur increased costs and restrictions, delays or cancellations in permitting or projects, which developments could expose us to significant costs and liabilities.

Compliance of our operations with these regulations or other laws, regulations and regulatory initiatives, or any other new environmental and occupational health and safety legal requirements could, among other things, require us to install new or modified emission controls on equipment or processes, incur longer permitting timelines, and incur significantly increased capital or operating expenditures, which costs may be significant. Moreover, any failure of our operations to comply with applicable environmental laws and regulations may result in governmental authorities taking actions against us that could adversely impact our operations and financial condition.

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

We may incur significant environmental cost 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, the EPA has 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, as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The EPA also published final rules under the CAA in 2012 and in 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Additionally, in 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. The BLM also published a final rule in 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in federal district 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 taken by the State of New York. 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. Additionally, non-governmental organizations may seek to restrict hydraulic fracturing, as has been the case in Colorado in recent years, when certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or costly in the future including, for example, by increasing mandatory setback distances of oil and natural gas operations, including hydraulic fracturing, from specific occupied structures and/or certain environmentally sensitive or recreational areas. 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 restrictions, delays or cancellations 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 BSEE, 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 re-consider the adoption, implementation 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 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 obligations. 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. However, in 2017, the Secretary of the U.S. Department of Interior issued Order 3350 (“Order 3350”), which directed the BOEM and the BSEE 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. As a result, 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 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 obligations. 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.

If we fail to comply with any 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

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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 or any subsequent 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 or any subsequent assignee 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 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. Over the past decade, the agency has been responsible for leading aggressive and comprehensive reforms regarding regulation and oversight of the offshore oil and natural gas industry. These reforms have resulted in more stringent offshore requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. However, as a result of the issuance of Order 3350 in 2017, the BSEE continues to reconsider certain regulations or regulatory initiatives governing offshore oil and gas safety and performance-related activities. For example, in December 2017, the BSEE proposed, and in September 2018 it finalized, revisions to its regulations regarding offshore drilling safety equipment, which revisions include the removal of an obligation 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. In another example, in May 2018, the BSEE issued a proposed rule to revise its existing regulations for well control and blowout preventer systems that had been bolstered by a final rule issued in 2016, but the May 2018 proposed rule has not been finalized.

Additionally, the Outer Continental Shelf Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and periodic unscheduled (unannounced) inspections 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 an alleged violation, the inspector typically issues an Incident of Noncompliance ("INC") to the operator that, depending on the severity of such violation, either serves as a warning to address such violation or requires a shut-in of a facility component or of the entire facility until such time as the violation is corrected. The warning INC is issued for a less severe or threatened condition and must be corrected within a reasonable amount of time, as specified on the INC, whereas the shut-in INC is for more serious conditions that 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.

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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 or businesses 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.
- Impact on leverage and access to capital

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.
- Dilution from issuance of new equity.
- Increased capital commitments or leverage.

We may be unable to successfully integrate the properties and businesses 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.

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

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

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

With the acquisition of our position in the Southern Delaware Basin, we have 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.

We have a limited operating history in West Texas. As a result, 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 in this area 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 $60.0 million, an increase of one percentage point in the interest rates would have resulted in an increase in interest expense during 2018 of $0.6 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:

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· 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.

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;

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- strategic actions by us or our competitors, such as acquisitions or restructurings;
- 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 are a smaller reporting company and we cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.

The SEC adopted amendments to the definition of “smaller reporting company” that became effective in September 2018. Under the new definition a company generally qualifies as a smaller reporting company if it has (1) a public float of less than $250 million or (2) annual revenues of less than $100 million during the most recently completed fiscal year and either (A) no public float or (B) a public float of less than $700 million. Public float is measured as of the last business day of the most recently completed second fiscal quarter. As a result of such amendments, we qualified as a “smaller reporting company ” for the fiscal year ended December 31, 2018. As a “smaller reporting company,” we are subject to reduced disclosure obligations in our SEC filings compared to other issuers, including, among other things, an exemption from the requirement to present five years of selected financial data and being subject to simplified executive compensation disclosures. Until such time as we cease to be a “smaller reporting company,” such reduced disclosure in our SEC filings may make it harder for investors to analyze our operating results and financial prospects. If some investors find our common stock less attractive as a result of any choices to reduce disclosure we may make, there may be a less active trading market for our common stock and our stock price may be more volatile.

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 Credit Facility 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.

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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, 2018, we had 33,637 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.

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 board of directors or at the written request of the holder or holders of one-half of all shares then outstanding and entitled to vote thereat; 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;
- 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.

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Our bylaws provide, subject to limited exceptions, that the Court of Chancery of the State of Delaware will be the sole and exclusive forum for certain stockholder litigation matters, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or stockholders.

Our bylaws provide, subject to limited exceptions, that unless we consent to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall, to the fullest extent permitted by law, be the sole and exclusive forum for any (i) derivative action or proceeding brought in the name or right of the Company or on its behalf, (ii) action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee or other agent of the Company to the Company or the Company's stockholders, (iii) action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, or our certificate of incorporation or bylaws, or (iv) action asserting a claim governed by the internal affairs doctrine.

Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock shall be deemed to have notice of and consented to the forum provisions in our bylaws. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or any of our directors, officers, other employees or stockholders which may discourage lawsuits with respect to such claims.

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