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;

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- 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.

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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

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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

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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

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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.

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

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

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

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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

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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.

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:

- 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 have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or
- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. This provision also has the effect of limiting financing transactions with interested stockholders that could be deemed favorable sources of capital. With approval of our board of directors and a majority of stockholders, we could change our state of incorporation and modify the antitakeover provisions applicable to us, or we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law.

Item 1B. Unresolved Staff Comments

None

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Item 2. Properties

As of December 31, 2018, we operated all of our offshore wells, with an average working interest of 53%, and operated 78% of our onshore wells with an average working interest of 62%. As of December 31, 2018, our properties were located in the following regions: Offshore Gulf of Mexico, Southeast Texas, South Texas, West Texas and Other.

Development, Exploration and Acquisition Expenditures

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

	Year Ended December 31,		
	2018	2017	2016
Property acquisition costs:			
Unproved	$ 10,339	$ 6,540	$ 29,767
Proved	—	—	—
Exploration costs	1,637	8,158	9,126
Development costs	42,516	45,016	1,890
Total costs	$ 54,492	$ 59,714	$ 40,783

Included in unproved property acquisition costs for each of the years ended December 31, 2018, 2017 and 2016 is $10.2 million, $5.9 million and $27.0 million, respectively, related to our acquisition of unproved property in the Southern Delaware Basin.

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

	Year Ended December 31,		
	2018	2017	2016
Property acquisition costs	$ —	$ —	$ —
Exploration costs	—	—	—
Development costs	169	429	395
Total costs incurred	$ 169	$ 429	$ 395

Drilling Activity

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

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	—	—	1	0.5	1	0.8
Productive (offshore)	—	—	—	—	—	—

Non-productive (onshore)	—	—	1	0.4	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	—	—	2	0.9	1	0.8

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	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive (onshore)	8	3.6	4	1.9	—	—
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	8	3.6	4	1.9	—	—

Exploration and Development Acreage

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

The following table shows the approximate developed and undeveloped acreage that we have an interest in, by region, at December 31, 2018.

	Developed Acreage (1)		Undeveloped Acreage (1)	
	Gross	Net (2)	Gross	Net (2)
Offshore GOM	9,213	6,643	—	—
Southeast Texas	12,934	8,309	7,056	3,813
South Texas	49,982	24,909	6,379	4,345
West Texas	11,158	4,893	12,461	3,526
Other (3)	9,890	5,724	46,078	31,821
Total	93,177	50,478	71,974	43,505

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.
(2) Net acres represent the number of acres attributable to our proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).
(3) Other includes acreage in Louisiana, Mississippi, Wyoming and East Texas.

Some of our offshore and onshore leases will expire over the next three years as follows, unless we establish production or take action to extend the terms of these leases:

	Year ending December 31,					
	2019		2020		2021	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore GOM	—	—	—	—	—	—
Southeast Texas	445	445	—	—	—	—
South Texas	—	—	—	—	—	—
West Texas	3,785	1,815	1,300	623	9	5
Wyoming	7,893	6,049	5,521	4,417	17,585	14,068

Total	12,123	8,309	6,821	5,040	17,594	14,073

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Production, Price and Cost History

The table below sets forth production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2018, 2017 and 2016. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six Mcf of natural gas. Average production costs include lease operating expense, transportation and processing costs and workover costs.

	Year Ended December 31,		
	2018	2017	2016
Production:			
Oil and condensate (thousand barrels)			
Offshore GOM	73	99	136
Southeast Texas	109	151	239
South Texas	78	95	128
West Texas	275	133	—
Other	34	40	94
Total oil and condensate	569	518	597
Natural gas (million cubic feet)			
Offshore GOM	7,704	11,113	13,991
Southeast Texas	957	1,328	2,059
South Texas	690	1,112	1,528
West Texas	285	82	—
Other	143	275	525
Total natural gas	9,779	13,910	18,103
Natural gas liquids (thousand barrels)			
Offshore GOM	287	330	420
Southeast Texas	88	115	217
South Texas	39	60	72
West Texas	59	12	—
Other	1	—	7
Total natural gas liquids	474	517	716
Total (million cubic feet equivalent)			
Offshore GOM	9,865	13,685	17,329
Southeast Texas	2,144	2,924	4,792
South Texas	1,390	2,038	2,729
West Texas	2,294	947	—
Other	346	529	1,132
Total production	16,039	20,123	25,982
Average Sales Price:			
Oil and condensate (per barrel)			
Offshore GOM	$ 67.59	$ 49.95	$ 37.84
Southeast Texas	66.55	50.09	39.23
South Texas	64.73	48.47	38.27
West Texas	54.52	47.76	—
Other	63.29	46.76	38.09
Total weighted average price	$ 60.43	$ 48.90	$ 38.52

Natural gas (per thousand cubic feet)			
Offshore GOM	$ 3.14	$ 2.99	$ 2.45
Southeast Texas	2.82	2.84	2.13
South Texas	2.92	2.97	2.24
West Texas	1.87	2.81	—
Other	2.95	3.03	4.08
Total weighted average price	$ 3.05	$ 2.97	$ 2.42

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	Year Ended December 31,		
	2018	2017	2016
Natural gas liquids (per barrel)			
Offshore GOM	$ 29.48	$ 26.78	$ 20.09
Southeast Texas	23.78	18.18	10.07
South Texas	18.46	11.88	7.87
West Texas	25.55	18.93	—
Other	42.28	24.22	17.03
Total weighted average price	$ 27.04	$ 22.97	$ 15.79
Total (per thousand cubic feet equivalent)			
Offshore GOM	$ 3.81	$ 3.43	$ 2.76
Southeast Texas	5.64	4.59	3.32
South Texas	5.60	4.22	3.26
West Texas	7.44	7.16	—
Other	7.36	5.65	5.43
Total weighted average price	$ 4.80	$ 3.90	$ 3.01
Average Production Costs:			
Offshore GOM	$ 0.84	$ 0.72	$ 0.60
Southeast Texas	2.83	$ 2.36	$ 1.49
South Texas	3.23	$ 2.63	$ 2.13
West Texas	1.10	$ 1.50	$ -
Other	3.23	$ 2.39	$ 2.59
Total average production costs	$ 1.40	$ 1.22	$ 1.00

Productive Wells

Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a "productive" well. The following table sets forth the number of gross and net productive natural gas and oil wells in which we owned an interest as of December 31, 2018:

	Natural Gas Wells		Oil Wells	
	Gross Wells (1)	Net Wells (2)	Gross Wells (1)	Net Wells (2)
Offshore GOM	7	3.8	—	—
Southeast Texas	11	7.6	39	23.2
South Texas	36	19.4	29	12.7
West Texas	—	—	12	5.3
Other	8	3.9	12	4.7
Total	62	34.7	92	45.9

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

Throughput Contract Commitment

The Company has a throughput agreement with a third party pipeline owner/operator through March 2020. See Note 13 – “Commitments and Contingencies” for further information.

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Natural Gas and Oil Reserves

Estimates of proved reserves and future net revenue as of December 31, 2018, and 2017 were prepared by NSAI and Cobb, our independent petroleum engineering firms in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE"). Approximately 82% and 18% of the proved reserves estimates shown herein at December 31, 2018 have been independently prepared by Cobb and NSAI, respectively. Cobb prepared the proved reserves estimates as of December 31, 2018 and 2017 for all of our offshore Gulf of Mexico properties and our onshore Southern Delaware Basin reserves, while NSAI prepared the proved reserves estimates as of December 31, 2018 and 2017 for our remaining onshore properties.

The technical individual at NSAI responsible for the preparation of our reserve estimates as of December 31, 2018 and 2017 has over 15 years of experience in the estimation and evaluation of reserves; is a licensed professional engineer in the state of Texas; and holds a Bachelor of Science Degree in Petroleum Engineering from the University of Tulsa. The technical individual at Cobb responsible for overseeing the preparation of our reserve estimates as of December 31, 2018 and 2017 has over 40 years of experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas; holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University; is a member of the SPE; and is a member of the Society of Petroleum Evaluation Engineers.

The estimates of proved reserves and future net revenue as of December 31, 2018 and 2017 were reviewed by our corporate reservoir engineering department that is independent of the operations department. The corporate reservoir engineering department interacts with geoscience, operating, accounting and marketing departments to review the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. All relevant data is compiled in a computer database application to which only authorized personnel are given access rights. Our Reservoir Engineering Manager is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for reviewing any reserves estimates prepared by our independent petroleum engineering firms. Our Reservoir Engineering Manager has a Bachelor of Science degree in Petroleum Engineering from Texas Tech University; is a licensed professional engineer in the state of Texas; has over 15 years of industry experience with positions of increasing responsibility; and is a member of the Society of Petroleum Engineers. She reports directly to our President and Chief Executive Officer. Reserves are also reviewed internally with senior management and presented to our board of directors in summary form on a quarterly basis.

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

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

	December 31, 2018	2017
Crude Oil and Condensate (MBbl) (1)		
Developed	3,103	3,364
Undeveloped	6,331	7,285
Total	9,434	10,649
Natural Gas (MMcf) (1)		
Developed	46,840	82,133
Undeveloped	7,366	9,586
Total	54,206	91,719
Natural Gas Liquids (MBbl) (1)		
Developed	2,297	3,596
Undeveloped	1,220	2,011
Total	3,517	5,607
Total MMcfe		
Developed	79,234	123,895
Undeveloped	52,677	65,359
Total (2)	131,911	189,254
Proved developed reserves percentage	60 %	65 %
Standardized measure (in thousands)	$ 218,944	$ 255,907
Prices utilized in estimates (3):		
Crude oil ($/Bbl)	$ 62.90	$ 47.41
Natural gas ($/MMBtu)	$ 3.02	$ 2.92
Natural gas liquids ($/Bbl)	$ 27.89	$ 18.59

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

(2) During the year ended December 31, 2018, proved reserves declined by approximately 57.3 Bcfe primarily due to, a 25.2 Bcfe decrease related to property sales throughout the year, a 25.3 negative revision related to our West Texas type curve resulting from analysis of longer term decline experience, a 17.0 Bcfe decrease in our GOM developed reserves related to negative revisions announced in the third quarter, a 16.0 Bcfe decrease due to 2018 production and a 5.6 Bcfe decrease due to a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded. Partially offsetting these reserve decreases were 31.5 Bcfe of new additions and extensions related to our drilling program and a 4.0 Bcfe positive revision resulting from higher commodity prices.

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

PV 10

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

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

	December 31, 2018	2017
Standardized measure of discounted future net cash flows	$ 218,944	$ 255,907
Future income taxes, discounted at 10%	1,563	1,376
Pre-tax net present value, discounted at 10%	$ 220,507	$ 257,283

The following table reflects our estimated proved reserves by category as of December 31, 2018 (dollars in thousands):

	Crude Oil and Condensate (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved		PV - 10
Proved developed producing	3,096	45,616	2,227	77,555	59	%	$ 174,718
Proved developed non-producing	7	1,224	70	1,679	1	%	1,580
Proved undeveloped	6,331	7,366	1,220	52,677	40	%	44,209
Total	9,434	54,206	3,517	131,911	100	%	$ 220,507

Our estimated net proved reserves as of December 31, 2018, volumetrically, were approximately 43% crude oil and condensate, 41% natural gas and 16% natural gas liquids.

Proved Developed Reserves

Total proved developed reserves declined from 123.9 Bcfe at December 31, 2017 to 79.2 Bcfe at December 31, 2018. This decline is primarily attributable to a 24.1 Bcfe decrease due to performance related revisions, a 17.7 Bcfe decrease related to property sales and a 16.0 Bcfe decrease attributable to production during the year. Partially offsetting these declines were 9.0 Bcfe of extensions and new additions generated by our 2018 drilling program.

The following table presents the changes in our total proved developed reserves for the year ended December 31, 2018:

	Proved Developed Reserves (Mmcfe)
Proved developed reserves at December 31, 2017	123,895
Revisions of previous estimates (1)	2,830
Extensions, discoveries and other additions (2)	9,029
Disposition of reserves in place (3)	(17,655)
Production	(15,965)
Negative revisions related to performance (4)	(24,063)
Conversions and other	1,163
Proved developed reserves at December 31, 2018	79,234

(1) Positive revisions due to higher commodity prices.

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

(3) Related to the sale of our assets in South and Southeast Texas and our Vermilion 170 offshore well.

(4) Primarily related to the previously announced revisions to our offshore properties as a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression in the Company's Eugene Island 11 field.

Proved Undeveloped Reserves

Total proved undeveloped reserves ("PUDs") decreased from 65.4 Bcfe at December 31, 2017 to 52.7 Bcfe at December 31, 2018. As noted in the table below, this decline was primarily attributable to negative performance related revisions and property sales, partially offset by the new additions and extensions from our 2018 drilling program in West Texas.

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

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factors may be considered such as technical merit, product type, location and available working interest partners. The PUD conversion rate in 2018 and 2017 was 9.1% and 0%, respectively, of the total net present value of the Company's total PUDs at the beginning of the applicable year.

The Company annually reviews any PUDs to ensure their development within five years from the date of originally adding the reserves. Assuming the Company is able to refinance or replace its Credit Facility, the Company's financial resources are expected to be sufficient to drill all of the remaining 52.7 Bcfe of proved undeveloped reserves within the five year period. Development costs relating to the 52.7 Bcfe at December 31, 2018 are projected to be approximately $156.1 million over the next five years. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Pursuit of Refinancing and Other Liquidity-Enhancing Alternatives" for a discussion on the Company's efforts to refinance or replace its Credit Facility. If the Company is unable to refinance or replace the Credit Facility there is substantial doubt about the Company's ability to continue as a going concern.

The following table presents the changes in our total proved undeveloped reserves for the year ended December 31, 2018:

	Proved Undeveloped Reserves (Mmcfe)
Proved undeveloped reserves at December 31, 2017	65,359
Revisions of previous estimates (1)	1,156
Extensions, discoveries and other additions (2)	22,506
Expired undeveloped reserves	(5,586)
Disposition of reserves in place (3)	(7,560)
Negative revisions related to performance (4)	(19,329)
Conversion to proved developed	(3,869)
Proved undeveloped reserves at December 31, 2018	52,677

(1) Positive revisions due to higher commodity prices.

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

(3) Related to the sale of our assets in South and Southeast Texas.

(4) Negative revisions primarily related to our West Texas type curve resulting from analysis of longer term decline experience.

Significant Properties

Summary proved reserve information for our properties as of December 31, 2018, by region, is provided below (excluding reserves attributable to our investment in Exaro) (dollars in thousands):

	Proved Reserves				
Regions	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (Mmcfe)	PV - 10 (1)

Offshore GOM	282	39,364	1,407	49,499	$ 100,062
Southeast Texas	1,525	3,927	511	16,144	30,972
South Texas	217	3,021	181	5,411	8,891
West Texas	7,108	7,859	1,418	59,018	77,197
Other	302	35	—	1,839	3,385
Total	9,434	54,206	3,517	131,911	$ 220,507

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

While we are reasonably certain of recovering our calculated reserves, the process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third party engineers must project production rates, estimate timing and amount of development expenditures, analyze available geological, geophysical, production and

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engineering data, and the extent, quality and reliability of all of this data may vary. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

Reserves Attributable to our Investment in Exaro

Estimates of proved reserves and future net revenue as of December 31, 2018 and 2017 associated with our investment in Exaro, which we account for using the equity method, were prepared by Von Gonten in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE.

Reserves as of December 31, 2018 and 2017 were reviewed by our corporate reservoir engineering department as described above. The technical individual at Von Gonten responsible for overseeing the preparation of our reserve estimates as of December 31, 2018 and December 31, 2017 has over 18 years of practical experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas; holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University; and is a member in good standing of the SPE.

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

	December 31, 2018	December 31, 2017
Crude Oil (MBbl)		
Developed	272	325
Undeveloped	—	4
Total	272	329
Natural Gas (MMcf)		
Developed	24,965	28,443
Undeveloped	—	303
Total	24,965	28,746
Total MMcfe		
Developed	26,595	30,390
Undeveloped	—	329
Total (3)	26,595	30,719
Proved developed reserves percentage	100 %	99 %
Standardized measure (in thousands) (1)	$ 21,001	$ 24,366
Prices utilized in estimates (2)		
Crude oil ($/Bbl)	$ 63.57	$ 48.91
Natural gas ($/MMBtu)	$ 2.99	$ 3.02

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

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

(3) During the year ended December 31, 2018, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 4.1 Bcfe.

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of December 31, 2017 and 2016 are disclosed in "Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Disclosures (Unaudited)". Reserves as of December 31, 2017 and 2016 were based on reserve reports generated by NSAI and Cobb, while the reserves associated with our 37% investment in Exaro were prepared by Von Gonten.

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Item 3. Legal Proceedings

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

On November 16, 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the Texas Court of Appeals, and in the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court's summary decision. In the first quarter of 2018, the Company filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company continues to vigorously defend this lawsuit and has filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. The Company is awaiting a response from the Texas Supreme Court as to whether it intends to review the case. In addition, the Company is also in the process of seeking amicus briefs from industry associations whose members would be affected by the Court of Appeals' ruling.

On September 14, 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the District Court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgement in the Company's favor. The plaintiff filed a motion for rehearing, which was denied in May 2018. The plaintiff has filed a petition requesting that the matter be reviewed by the Texas Supreme Court; the parties are awaiting a response from the Texas Supreme Court as to whether it intends to review the case. The Company continues to vigorously defend this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

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

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Our common stock is listed on the NYSE American under the symbol "MCF".

As of March 11, 2019, there were approximately 166 registered shareholders of our common stock.

Holders of common stock are entitled to such dividends as may be declared by the board of directors out of funds legally available. Therefore, any decision to pay future dividends on our common stock will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, capital requirements and other factors our board of directors may deem relevant. We do not anticipate paying any cash dividends on our common stock in the foreseeable future, as we currently intend to retain all future earnings to fund the development and growth of our business. Our Credit Facility with Royal Bank of Canada and other lenders currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. No shares were purchased for the years ended December 31, 2018 and 2017. As of December 31, 2018, the Company has $31.8 million available under its share repurchase program.

On November 2, 2018, the Company amended its Credit Facility, which among other things, restricts the Company from repurchasing shares under this program.

In addition, the Company withheld the following shares, outside of the repurchase program, on a cashless basis from employees as their payment of withholding taxes due on vesting shares of restricted stock previously issued under our stock-based compensation plans:

Period	Total Number of Shares Withheld	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet be Purchased Under Program
October 2018	12,321	$ 5.75	—	—
November 2018	1,112	$ 4.43	—	—
December 2018	167	$ 3.25	—	—
	13,600	$ 5.61	—	$ 31.8 million

Item 6. Selected Financial Data

Not applicable.

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

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

Overview

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

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.

Our production for the year ended December 31, 2018 was approximately 16.0 Bcfe (or 43.9 Mmcfe/d) and was 62% offshore and 38% onshore. Our production for the three months ended December 31, 2018 was approximately 3.7 Bcfe (or 39.8 Mmcfe/d) and was 63% offshore and 37% onshore. As of December 31, 2018, our proved reserves were approximately 38% offshore and 62% onshore and were 60% proved developed, which were approximately 62% offshore and 38% onshore.

Revenues and Profitability

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

Reserve Replacement

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

Use of Estimates

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

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

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Going Concern Assessment

As discussed below under “Capital Resources and Liquidity,” our Credit Facility (as defined below) currently matures on October 1, 2019. Over the past few months, we have been in discussions with our current lenders and other sources of capital regarding a possible refinancing and/or replacement of our existing Credit Facility. 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. These conditions raise substantial doubt about our ability to continue as a going concern. However, the accompanying financial statements have been prepared assuming we will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The accompanying 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. As discussed below under “Capital Resources and Liquidity,” management is evaluating plans to refinance and/or replace the Credit Facility.

Results of Operations

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

	Three Months Ended							
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
fshore OM								
tch and ary se (1)	35.4	36.3	32.2	30.8	29.0	21.0	25.2	24.2
rmilion 0 (2)	4.6	3.1	4.2	3.5	3.0	2.7	2.0	1.1
uth mbalier (3)	0.5	0.2	0.1	—	—	—	—	—
utheast xas (4)	8.6	8.2	7.8	7.5	7.3	6.4	6.0	3.9
uth xas (5)	6.4	5.6	4.6	5.8	5.3	4.5	3.1	2.4
est xas	0.6	3.3	3.2	3.2	4.5	6.7	6.4	7.5
her (6)	1.5	1.3	1.1	1.0	0.9	1.1	0.9	0.7
	57.6	58.0	53.2	51.8	50.0	42.4	43.6	39.8

(1) Includes a decreased production rate of 4.2 Mmcfe/d due to downtime related to compressor installation and maintenance during the three months ended June 30, 2018. Our GOM production was not materially affected by Hurricane Michael which passed through the northeastern GOM in October 2018.

(2) Includes a decreased production rate of 0.8 Mmcfe/d due to temporary pipeline limitations during the three months ended June 30, 2017 and 0.5 Mmcfe/d for the three months ended December 31, 2018.

(3) South Timbalier 17 ceased production in August 2017.

(4) Includes Woodbine production from Madison and Grimes counties and conventional production in others. Decrease in production during three months ended December 31, 2018 is primarily due to the Liberty and Hardin County property sale in November 2018.

(5) Includes Eagle Ford and Buda production from Karnes, Zavala and Dimmit counties, and conventional production in others, prior to June 30, 2018. Does not include Karnes County in the three months ended June 30, 2018 and forward due to its sale in March 2018.

(6) Includes onshore wells primarily in East Texas and Wyoming.

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Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2018 and 2017. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six Mcf of natural gas. Reported operating expenses include production taxes, such as ad valorem and severance.

	Year Ended December 31,		
	2018	2017	%
Revenues (thousands):			
Oil and condensate sales	$ 34,413	$ 25,347	36 %
Natural gas sales	29,824	41,317	(28) %
NGL sales	12,850	11,881	8 %
Total revenues	$ 77,087	$ 78,545	(2) %
Production:			
Oil and condensate (thousand barrels)			
Dutch and Mary Rose	68	89	(24) %
Vermilion 170	5	10	(50) %
Southeast Texas	109	151	(28) %
South Texas	78	95	(18) %
West Texas	275	133	107 %
Other	34	40	(15) %
Total oil and condensate	569	518	10 %
Natural gas (million cubic feet)			
Dutch and Mary Rose	7,017	9,891	(29) %
Vermilion 170	687	1,222	(44) %
Southeast Texas	957	1,328	(28) %
South Texas	690	1,112	(38) %
West Texas	285	82	248 %
Other	143	275	(48) %
Total natural gas	9,779	13,910	(30) %
Natural gas liquids (thousand barrels)			
Dutch and Mary Rose	273	310	(12) %
Vermilion 170	14	20	(30) %
Southeast Texas	88	115	(23) %
South Texas	39	60	(35) %
West Texas	59	12	392 %
Other	1	—	100 %
Total natural gas liquids	474	517	(8) %
Total (million cubic feet equivalent)			
Dutch and Mary Rose	9,062	12,283	(26) %
Vermilion 170	803	1,402	(43) %
Southeast Texas	2,144	2,924	(27) %
South Texas	1,390	2,038	(32) %
West Texas	2,294	947	142 %
Other	346	529	(35) %

Total production	16,039	20,123	(20) %

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	Year Ended December 31,			
	2018	2017	%	
Daily Production:				
Oil and condensate (thousand barrels per day)				
Dutch and Mary Rose	0.2	0.2	(24)	%
Vermilion 170	—	—	(50)	%
Southeast Texas	0.3	0.4	(28)	%
South Texas	0.2	0.3	(18)	%
West Texas	0.8	0.4	107	%
Other	0.1	0.1	(15)	%
Total oil and condensate	1.6	1.4	10	%
Natural gas (million cubic feet per day)				
Dutch and Mary Rose	19.2	27.1	(29)	%
Vermilion 170	1.9	3.3	(44)	%
Southeast Texas	2.6	3.6	(28)	%
South Texas	1.9	3.0	(38)	%
West Texas	0.8	0.2	248	%
Other	0.4	0.9	(48)	%
Total natural gas	26.8	38.1	(30)	%
Natural gas liquids (thousand barrels per day)				
Dutch and Mary Rose	0.8	0.9	(12)	%
Vermilion 170	—	—	(30)	%
Southeast Texas	0.2	0.3	(23)	%
South Texas	0.1	0.2	(35)	%
West Texas	0.2	—	392	%
Other	—	—	100	%
Total natural gas liquids	1.3	1.4	(8)	%
Total (million cubic feet equivalent per day)				
Dutch and Mary Rose	24.8	33.7	(26)	%
Vermilion 170	2.2	3.8	(43)	%
Southeast Texas	5.9	8.0	(27)	%
South Texas	3.8	5.6	(32)	%
West Texas	6.3	2.6	142	%
Other	0.9	1.4	(35)	%
Total production	43.9	55.1	(20)	%
Average Sales Price:				
Oil and condensate (per barrel)	$ 60.43	$ 48.90	24	%
Natural gas (per thousand cubic feet)	$ 3.05	$ 2.97	3	%
Natural gas liquids (per barrel)	$ 27.04	$ 22.97	18	%
Total (per thousand cubic feet equivalent)	$ 4.80	$ 3.90	23	%
Expenses (thousands):				
Operating expenses	$ 25,552	$ 27,183	(6)	%
Exploration expenses	$ 1,637	$ 1,106	48	%
Depreciation, depletion and amortization	$ 41,657	$ 47,215	(12)	%
Impairment and abandonment of oil and gas properties	$ 103,732	$ 2,395	*	

General and administrative expenses	$ 24,157	$ 24,161	(0)	%
Gain (Loss) from investment in affiliates (net of taxes)	$ (12,721)	$ 2,697	(572)	%
Other (Income) Expense	$ 10,921	$ 2,780	293	%
Selected data per Mcfe:				
Operating expenses	$ 1.59	$ 1.35	18	%
General and administrative expenses	$ 1.51	$ 1.20	26	%
Depreciation, depletion and amortization	$ 2.60	$ 2.35	11	%

* Greater than 1,000%

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Natural Gas, Oil and NGL Sales and Production

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

We reported revenues of approximately $77.1 million for the year ended December 31, 2018, compared to revenues of approximately $78.5 million for the year ended December 31, 2017. This slight decrease in revenues was primarily due to a reduction in natural gas production attributable to 2018 non-core property sales, the expected year over year decline in our offshore properties and the reduction in our fourth quarter 2018 drilling program in response to declining oil prices; declines which were substantially offset by the benefit of higher commodity prices in 2018.

Total production for the year ended December 31, 2018 was approximately 16.0 Bcfe, or 43.9 Mmcfe/d, compared to approximately 20.1 Bcfe, or 55.1 Mmcfe/d, in the prior year. The decrease was attributable to an approximate 13 Mmcfe/d decline in production resulting from normal field decline, an approximate 2 Mmcfe/d decline due to non-core property sales, and an approximate 1 Mmcfe/d decline due to shut-in periods at Eugene Island for compressor installation in June. Partially offsetting these decreases in production was an increase of approximately 4 Mmcfe/d of new production (88% oil and NGLs) from drilling on our Southern Delaware Basin acreage.

Net natural gas production for the year ended December 31, 2018 was approximately 26.8 Mmcf/d, compared with approximately 38.1 Mmcf/d for the year ended December 31, 2017. Net oil production increased from approximately 1,400 barrels per day to 1,600 barrels per day, while NGL production decreased from approximately 1,400 barrels per day to 1,300 barrels per day. The higher-unit value oil and NGL production (but lower volume equivalency than gas) increased from 31% to 39% of total production due to the success of our oil-weighted West Texas drilling program. West Texas accounted for 14% of total equivalent production for the year ended December 31, 2018, as compared to 5% of total equivalent production for the year ended December 31, 2017.

Average Sales Prices

The average equivalent sales price realized for the years ended December 31, 2018 and 2017 was $4.80 per Mcfe and $3.90 per Mcfe, respectively, a result of increases in all commodity prices and the increase in oil and liquids production as a percentage of the total production base. The average realized price of natural gas for the years ended December 31, 2018 and 2017 was $3.05 per Mcf and $2.97 per Mcf, respectively. The average realized price for oil for the years ended December 31, 2018 and 2017 was $60.43 per barrel and $48.90 per barrel, respectively. The average realized price for NGLs for the years ended December 31, 2018 and 2017 was $27.04 per barrel and $22.97 per barrel, respectively.

Operating Expenses (including production taxes)

Total operating expenses for the year ended December 31, 2018 were approximately $25.6 million, or $1.59 per Mcfe, compared to approximately $27.2 million, or $1.35 per Mcfe, for the year ended December 31, 2017. The table below provides additional detail of total operating expenses for those periods.

	Twelve Months Ended December 31,			
	2018		2017	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 17,471	$ 1.09	$ 17,458	$ 0.87
Production & ad valorem taxes	3,070	0.19	2,568	0.13
Transportation & processing costs	2,791	0.17	4,866	0.24
Workover costs	2,220	0.14	2,291	0.11
Total operating expenses	$ 25,552	$ 1.59	$ 27,183	$ 1.35

Transportation and processing costs decreased by 43% for the year ended December 31, 2018, compared to the prior year, primarily due to lower offshore production and an adjustment related to an offshore processing fee overcharge. In addition, a portion of the decrease in the current year can be attributed to the routing of substantially all of our offshore gas production through a lower cost pipeline, and the routing of our condensate through a new pipeline we constructed in early 2018.

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Exploration Expenses

We reported approximately $1.6 million and $1.1 million of exploration expenses for the years ended December 31, 2018 and 2017, respectively, which were primarily related to geological and geophysical software, seismic data licensing fees and mapping services.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expense for the year ended December 31, 2018 was approximately $41.7 million, or $2.60 per Mcfe, compared to approximately $47.2 million, or $2.35 per Mcfe, for the year ended December 31, 2017. Although depletion expense decreased during the current year, the higher depletion expense per unit was attributable primarily to the decline in our offshore production as a percentage of our total production for the year, as the offshore has a lower DD&A rate.

Impairment and Abandonment of Oil and Gas Properties

Impairment and abandonment expenses for the year ended December 31, 2018 included proved property impairment of approximately $101.9 million. Included in the impairment charges incurred in 2018 was a $61.7 million impairment of the carrying costs of our offshore Gulf of Mexico proved properties primarily due to revised proved reserve estimates made during the quarter ended September 30, 2018. This impairment was primarily a result of 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 the impairment of 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. See Note 4 – "Acquisitions and Dispositions" for further information regarding the property dispositions. During the year ended December 31, 2018, we recognized impairment expense of approximately $1.3 million related to unproved properties due to expiring leases.

Impairment and abandonment expenses for the year ended December 31, 2017 included proved property impairment of approximately $0.3 million related to the revised estimated reserves for our Tuscaloosa Marine Shale properties and $1.5 million for the partial impairment of two unused offshore platforms that were sold during the year.

General and Administrative Expenses

Total general and administrative expenses for each of the years ended December 31, 2018 and 2017 was approximately $24.2 million. Cash general and administrative expenses, i.e. excluding non-cash stock based compensation expense, were $19.4 million for the current year compared to cash expenses of $18.1 million for the prior year. Current year cash costs included $1.5 million in lower salary and bonus expense due to smaller staff, offset by a $1.8 million severance payment made upon the resignation of our former President and CEO. Non-cash stock based compensation expense was approximately $4.8 million in the current year and approximately $6.1 million in the prior year.

Gain (loss) from Affiliates

For the year ended December 31, 2018, the Company recorded a loss from affiliates of approximately $12.6 million, net of zero expense, related to our equity investment in Exaro, compared with a gain from affiliates of approximately $2.7 million, net of zero tax expense, for the year ended December 31, 2017.

Other Income (Expense)

Other income for the year ended December 31, 2018 was approximately $10.9 million, which consists primarily of a $13.2 million gain on the sale of assets, a $1.9 million net gain on derivatives and a $0.9 million reimbursement claim under our property and casualty insurance policy. Other income was partially offset by interest expense of $5.5 million.

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Other income for the year ended December 31, 2017 was approximately $2.8 million, which consists of a $2.3 million gain on sale of assets, a $3.3 million net gain on derivatives and a $1.3 million gain related to the sale of our investment in a small private service company. Other income was partially offset by interest expense of $4.1 million.

Capital Resources and Liquidity

Our primary cash requirements are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be drawn under our Credit Facility.

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the periods indicated, in thousands.

	Year ended December 31,	
	2018	2017
Net cash provided by operating activities	$ 23,477	$ 34,686
Net cash used in investing activities	$ (30,687)	$ (65,450)
Net cash provided by financing activities	$ 7,210	$ 30,764
Cash and cash equivalents at the end of the period	$ —	$ —

Cash flow from operating activities, including changes in working capital, provided approximately $23.5 million in cash for the year ended December 31, 2018 compared to $34.7 million for the year ended December 31, 2017. Cash flow from operating activities, excluding changes in working capital, provided approximately $22.1 million in cash for the year ended December 31, 2018 compared to $29.6 million for the year ended December 31, 2017. Cash provided due to changes in working capital were approximately $1.4 million during 2018, compared to $5.1 million during 2017 and represent normal receivable and payable activity during the period.

Net cash flows used in investing activities were $30.7 million for the year ended December 31, 2018. We expended $59.0 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases, partially offset by $27.8 million in cash proceeds from the sale of our non-core properties.

Net cash flows used in investing activities were $65.5 million for the year ended December 31, 2017. We expended $66.6 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases, partially offset by $1.1 million in cash proceeds from the sale of non-core properties.

Cash flows provided by financing activities were approximately $7.2 million for the year ended December 31, 2018 compared to $30.8 million used in financing activities in 2017. Included in 2018 activity was $33.0 million in proceeds from our equity offering and approximately $25.4 million in net repayments of outstandings under our Credit Facility (defined below). 2017 activity was primarily related to net borrowings under our Credit Facility.

Credit Facility

Our $500 million revolving Credit Facility with Royal Bank of Canada and other lenders (the “Credit Facility”) currently matures on October 1, 2019. The borrowing base under the facility is redetermined each November and May. On November 2, 2018, the Company entered into the Sixth Amendment to the Credit Facility (the “Sixth

Amendment”), whereby the current borrowing base was reaffirmed at $105 million and was reduced to $90 million on January 31, 2019.

The Sixth Amendment also provided for, among other things: (i) reducing the letter of credit issuance commitment capacity from $20.0 million to $5.0 million; (ii) waiving compliance with the required minimum 1.00 to 1.00 Current Ratio for the fiscal quarters ended September 30, 2018 and December 31, 2018; (iii) eliminating an exception from the restriction on payment of dividends, stock repurchases or redemptions of equity for repurchases under certain circumstances; (iv) waiving advance notice and a requirement for delivery of a revised reserve report related to the Liberty and Hardin County, Texas asset sale; and (v) required delivery to the administrative agent of internally-prepared monthly consolidated financial statements of the Company within 25 days of the end of such month.

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As of December 31, 2018, we had $60.0 million outstanding under the Credit Facility, and $1.9 million in outstanding letters of credit. As of December 31, 2018, the borrowing availability under the Credit Facility was $43.1 million.

The Credit Facility contains restrictive covenants which, among other things, restricts the declaration or payment of dividends by Contango, prevents the repurchase of shares and requires a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the Credit Facility agreement. Our compliance with these covenants is tested each quarter. At December 31, 2018, we were in compliance with all of our covenants under the Credit Facility. 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. The Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, audited financials that include a going concern qualification, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events. As of December 31, 2018, we were in compliance with all of our covenants under the Credit Facility agreement. See Note 12 to our Financial Statements -"Indebtedness" for a more detailed description of terms and provisions of our Credit Facility.

Pursuit of Refinancing and Other Liquidity-Enhancing Alternatives

Over the past few months, we have been in discussions with our current lenders and other sources of capital regarding a possible refinancing and/or replacement of our existing 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. These conditions raise substantial doubt about our ability to continue as a going concern. However, the accompanying financial statements have been prepared assuming we will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The accompanying 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.

The refinancing and/or replacement of the Credit Facility could be made in conjunction with a substantial acquisition or disposition, an issuance of unsecured or non-priority secured debt or preferred or common equity, non-core property monetization, potential monetization of certain midstream and/or water handling facilities, etc. or a combination of the foregoing. These discussions have included a possible new, replacement or extended Credit Facility that would be expected to provide additional borrowing capacity for future capital expenditures. 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.

Future Capital Requirements

Our future crude oil, natural gas and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We intend to grow our reserves and production by further exploiting our existing property base through drilling opportunities in our resource plays and in our conventional onshore inventory in West Texas and the Texas Gulf Coast, with activity in any particular area and period of time to be a function of liquidity, market and field economics. We anticipate that acquisitions, including those of undeveloped leasehold interests, will continue to play a role in our business strategy as those opportunities arise from time to time; however, there can be no assurance that we will be successful in consummating any acquisitions, or that any such acquisition entered into will be successful. These potential acquisitions are not part of our current capital budget and would require additional capital. Natural gas and oil prices continue to be volatile, and our financial resources may be insufficient to fund any of these opportunities. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

If we are able to refinance and/or replace our Credit Facility, we believe that our internally generated cash flow and proceeds from the sale of non-core assets, combined with availability under our Credit Facility will be sufficient to

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meet the liquidity requirements necessary to fund our daily operations and planned capital development and to meet our debt service requirements for the next twelve months. If we are not able to refinance and/or replace our Credit Facility, there is substantial doubt about our ability to continue as a going concern. As noted above under " Pursuit of Refinancing and Other Liquidity-Enhancing Alternatives", our management is discussing with our current lenders a possible refinancing and/or replacement of our existing Credit Facility and evaluating alternatives. There is no assurance, however, that such efforts 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. Our ability to execute on our growth strategy will be determined, in large part, by our cash flow and the availability of debt and equity capital at that time. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors.

Our 2019 capital budget will be focused primarily on the Southern Delaware Basin, while at the same time: (i) preserving our financial position, including limiting capital expenditures to internally generated cash flow and proceeds from the sale of non-core assets; (ii) focusing drilling expenditures on strategic projects that provide good investment returns in the current price environment; and (iii) identifying opportunities for cost efficiencies in all areas of our operations. Our current capital budget for 2019 should allow us to meet our contractual requirements and remain in position to preserve our term acreage where appropriate during this challenging period for our industry. We will continuously monitor the commodity price environment, and if warranted, make adjustments to our investment strategy as the year progresses.

Inflation and Changes in Prices

While the general level of inflation affects certain costs associated with the energy industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have, a material effect on our operations; however, we cannot predict these fluctuations.

Income Taxes

During the year ended December 31, 2018, we paid approximately $81 thousand in state income taxes and no federal income taxes. During the year ended December 31, 2017, we paid approximately $0.6 million in state income taxes and no federal income taxes.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in Note 2 of Notes to Consolidated Financial Statements included as part of this Form 10-K. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company's consolidated financial statements:

Oil and Gas Properties - Successful Efforts

Our application of the successful efforts method of accounting for our natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as

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development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Reserve Estimates

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

Actual production, revenues and expenditures with respect to the Company’s reserves will likely vary from estimates, and such variances may be material. Holding all other factors constant, a reduction in the Company’s proved reserve estimate at December 31, 2018 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $0.4 million, $0.9 million and $1.4 million, respectively.

Impairment of Natural Gas and Oil Properties

The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. An impairment loss associated with an asset group is the amount by which the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. An asset’s fair value is preferably indicated by a quoted market price in the asset’s principal market. Unlike many businesses where independent appraisals can be obtained for items such as equipment, oil and gas proved reserves are unique assets. Most oil and gas valuations are based on a combination of the income approach and market approach methodologies. We utilize the income approach also known as the discounted cash flow (“DCF”) approach. Under the DCF method in determining fair value, there are specific guidelines and ranges within the evaluation that we can consider and estimate.

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

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Derivative Instruments

The Company elected to not designate any of its derivative positions for hedge accounting At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives, along with the realized gain or loss for settled derivatives, is reported in “Other Income (Expense)” as “Gain on derivatives, net”.

Income Taxes

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

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

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2018, we had federal net operating loss (“NOL”) carryforwards of $380.8 million. Generally, these NOLs are available to reduce future taxable income and the related income tax liability subject to the limitations set forth in Section 382. However, these NOLs are subject to an annual Section 382 limitation as a result of the ownership change that occurred in connection with our stock offering in November 2018. Given our annual Section 382 limitation and the uncertainty of our ability to generate taxable income, a valuation allowance of $71.0 million has been recorded for the year ended December 31, 2018 against the deferred tax assets, reduced by the amount of the deferred tax liability.

Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. See Note 15 - "Income Taxes” to our consolidated financial statements.

Recent Accounting Pronouncements

Leases: In February 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2016-02: Leases (Topic 842) (ASU 2016-02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP treatment of leases and that proposed in ASU 2016-02 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize a right-of-use asset and lease liability arising from such operating leases on the balance sheet.

ASU 2016-02 contains several optional practical expedients, one of which is referred to as the “package of three practical expedients”. The expedients must be taken together and allow entities to: (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. The Company has elected to apply this practical expedient package to all of its leases. The Company has also chosen to implement the “short-term accounting policy election” which allows the Company to not include leases with an initial term of 12 months or less on the balance sheet.

For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company adopted this standard on January 1, 2019, and the impact of adoption is immaterial.

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Other: In August 2016, the FASB issued ASU No. 2016-15: Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments. The main objective of this update is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The eight cash flow updates relate to the following issues: 1) debt prepayment or debt extinguishment costs; 2) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; 3) contingent consideration payments made after a business combination; 4) proceeds from the settlement of insurance claims; 5) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies; 6) distributions received from equity method investees; 7) beneficial interest in securitization transactions; and 8) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The provisions of this update are not expected to have a material impact on the Company’s presentation of cash flows.

In January 2017, the FASB issued ASU No. 2017-01: Business Combinations (Topic 805) Clarifying the Definition of a Business (ASU 2018-01). The amendments in this update are intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. Public business entities should apply the amendments in this update to annual periods beginning after December 15, 2018, including interim periods within those periods. The amendments in this update should be applied prospectively on or after the effective date. No disclosures are required at transition. The provisions of this update are not expected to have a material impact on the Company’s financial position or results of operations.

In August 2018, the FASB issued ASU 2018-13 – Fair Value Measurement (Topic 820). The amendments in ASU 2018-13 modify the disclosure requirements on fair value measurements in Topic 820. The amendments in this update are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The provisions of this update are not expected to have a material impact on the Company’s financial position or results of operations.

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of December 31, 2018, the primary off-balance sheet arrangements that we have entered into included short-term drilling rig contracts and operating lease agreements, all of which are customary in the oil and gas industry. Other than the off-balance sheet arrangements shown under operating leases and drilling rig in the commitments and contingencies table, we have no other arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

Item 8. Financial Statements and Supplementary Data

The financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented on pages F-1 through F-35 of this Form 10-K.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of the Company’s senior management of the effectiveness of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”)) as of December 31, 2018, the end of the period covered by this report. Based on that evaluation, the Company’s management, including the President and Chief Executive Officer and the Chief Financial Officer, concluded that the Company’s disclosure controls and procedures

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were effective as of such date to ensure that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fiscal quarter ended December 31, 2018 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in 2013 Internal Control-Integrated Framework, the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2018.

Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Form 10-K, has audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Contango Oil & Gas Company

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Contango Oil & Gas Company (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in the 2013 Internal Control— Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 Internal Control— Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2018, and our report dated March 18, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/ s / GRANT THORNTON LLP

Houston, Texas

March 18, 2019

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Item 9B. Other Information

On March 14, 2019, the Company amended its Certificate of Incorporation, as amended, by filing with the Secretary of State of the State of Delaware a Certificate of Elimination of Series A Junior Participating Preferred Stock of the Company, which has the effect of eliminating from the Company's Certificate of Incorporation, as amended, all matters set forth in the Certificate of Designations of Series A Preferred Stock filed with the Secretary of State of the State of Delaware on August 1, 2018, and all authorized shares designated to such series of preferred stock have been returned to the status of authorized but unissued shares of preferred stock of the Company without designation as to series.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2018 Annual Meeting of Stockholders (the "Proxy Statement") under the headings "Proposal 1: Election of Directors", "Executive Compensation", "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance and our Board" and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after December 31, 2018.

Code of Ethics

In January 2014, our board of directors adopted our current Code of Business Conduct and Ethics ("Code of Conduct") which applies to all directors, officers and employees of the Company, including our principal executive, principal financial and principal accounting officers, or persons performing similar functions. Our Code of Conduct is available on the Company's website at www.contango.com. Changes in and waivers to the Code of Conduct for the Company's directors, chief executive officer and certain senior financial officers will be posted on the Company's website within four business days and maintained for at least 12 months. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this report.

Item 11. Executive Compensation

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Other than as set forth below, the information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading "Security Ownership of Certain Other Beneficial Owners and Management" and is incorporated herein by reference.

Securities authorized for issuance under equity compensation plans

The following table sets forth information about our equity compensation plans at December 31, 2018:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights (1)	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders			
Second Amended and Restated 2009 Incentive Compensation Plan	236,799 (2)	$ —	1,854,588
Equity plans not approved by security holders			
2005 Stock Incentive Plan ("Crimson Plan")	33,637	$ 55.82	—

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(1) The weighted-average exercise price does not take into account the shares issuable upon vesting of outstanding Performance Stock Units, which have no exercise price.
(2) Represents shares issuable upon the vesting of Performance Stock Units awarded under the plan. The actual number of shares that a grant recipient receives at the end of the period may range from 0% to 300% of the target number of shares.

The 2005 Stock Incentive Plan was adopted by our Board in conjunction with the merger with Crimson Exploration, Inc. (“Crimson”). Prior to such merger, it had been approved by Crimson Stockholders. The plan expired on February 25, 2015 and therefore no additional shares are available for grant.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the headings “Corporate Governance and our Board”, “Transactions with Related Persons” and “Executive Compensation” and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the subheading “Principal Accountant Fees and Services” and is incorporated herein by reference.

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GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this report.

2D seismic or 3D seismic. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe. Barrel of oil equivalent per day determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Boe per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or crude oil in another reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

IP 30. The average daily hydrocarbon production rate of the initial 30 days of full commercial production. IP 30 average daily production rates are subject to natural and mechanical declines and are accordingly not comparable to the average daily production rate over the life of the well.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. million barrels of crude oil or other liquid hydrocarbons.

MMBtu. million British Thermal Units. One MMBtu equates to approximately one Mcf.

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MMcf. million cubic feet of natural gas.

MMcfe. million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed producing reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(6) of Regulation S-X, which defines proved developed reserves as reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves.   Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

The area of a reservoir considered proved includes (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geological and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geological, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and the project has been approved for development by all necessary parties and entities, including governmental entities.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(31) of Regulation S-X, which defines proved undeveloped reserves as reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances should estimates for proved undeveloped reserves be

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attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Total Measured Depth or TMD. The total measured drilled vertical and horizontal depth of a well.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest or WI. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules:

The financial statements are set forth in pages F-1 to F-29 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibits:

The following is a list of exhibits filed as part of this Form 10-K. Where so indicated by a footnote, exhibits, which were previously filed, are incorporated herein by reference.

Exhibit Number	Description
2.1	Agreement and Plan of Merger, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Crimson Exploration Inc., dated as of April 29, 2013 (filed as Exhibit 2.1 to the Company's report on Form 8-K, dated as of April 29, 2013, as filed with the Securities and Exchange Commission on May 1, 2013, and incorporated by reference herein).
3.1	Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's report on Form 8-K, dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000, and incorporated by reference herein).
3.2	Third Amended and Restated Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015, as filed with the Securities and Exchange Commission on March 3, 2015, and incorporated by reference herein).
3.3	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.4 to the Company's report on Form 10-QSB for the quarter ended September 30, 2002, dated November 14, 2002, as filed with the Securities and Exchange Commission, and incorporated by reference herein).
3.4	Certificate of Designations of Series A Junior Participating Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018 and incorporated by reference herein).
3.5	Certificate of Elimination of Series A Junior Participating Preferred Stock of Contango Oil & Gas Company, as filed with the Secretary of State of the State of Delaware on March 14, 2019. †
4.1	Facsimile of common stock certificate of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Form 10-SB Registration Statement, as filed with the Securities and Exchange Commission on October 16, 1998, and incorporated by reference herein).
4.2	Registration Rights Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, OCM Crimson Holdings, LLC and OCM GW Holdings, LLC (filed as Exhibit 10.9 to the Company's report on Form 8-K, dated as of April 29, 2013, as filed with the Securities and Exchange Commission on May 1, 2013, and incorporated by reference herein).
4.3	Rights Agreement, dated as of August 1, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and

		Exchange Commission on August 2, 2018, and incorporated by reference herein).
4.4		Amendment to the Rights Agreement, dated as of November 21, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated November 21, 2018, as filed with the Securities and Exchange Commission on November 21, 2018, and incorporated by reference herein).
10.1	*	Amended and Restated 2005 Stock Incentive Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated as of October 1, 2013, as filed with the Securities and Exchange Commission on October 2, 2013, and incorporated by reference herein).
10.2	*	Contango Oil & Gas Company Amended and Restated 2009 Incentive Compensation Plan (filed as an exhibit to the Company's Schedule 14A on Definitive Proxy Statement for 2014, as filed with the Securities and Exchange Commission on April 11, 2014, and incorporated by reference herein).

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Exhibit Number		Description
10.3		First Amended and Restated Limited Liability Company Agreement dated as of March 31, 2012 between Contango Oil & Gas Company and Exaro Energy III LLC (filed as Exhibit 10.1 to the Company's report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012, and incorporated by reference herein).
10.4		Second Amended and Restated Limited Liability Company Agreement dated as of February 1, 2013 between Contango Oil & Gas Company and Exaro Energy III LLC. †
10.5		Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 9, 2008 between Contango Offshore Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.48 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.6		Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 7, 2009 between Contango Offshore Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.49 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.7		Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of January 29, 2010 between Contango Offshore Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.50 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.8		Participation Agreement covering OCS-G 33596, Vermilion 170, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.51 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.9		Participation Agreement covering Tuscaloosa Marine Shale, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc. (filed as Exhibit 10.56 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.10		Letter Agreement dated as of June 8, 2012 between Juneau Exploration LP and Contango Operators, Inc. (filed as Exhibit 10.57 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.11		Agreement to Purchase Overriding Royalty Interest, dated March 1, 2010 between Contango Offshore Exploration LLC and Juneau Exploration LP (filed as Exhibit 10.60 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.12	*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and Allan D. Keel (filed as Exhibit 10.11 to the Company's report on Form 10-K for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on March 15, 2017, and incorporated by reference herein).
10.13	*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and E. Joseph Grady (filed as Exhibit 10.12 to the Company's report on Form 10-K for

		the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on March 15, 2017, and incorporated by reference herein).
10.14	*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and Jay S. Mengle (filed as Exhibit 10.17 to the Company's report on Form 10-K for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on March 15, 2017, and incorporated by reference herein).
10.15	*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and Thomas H. Atkins (filed as Exhibit 10.18 to the Company's report on Form 10-K for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on March 15, 2017, and incorporated by reference herein).

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Exhibit Number		Description
10.16		Participation Agreement covering Timbalier Island Prospect, South Timbalier Area Block 17, S.L. 21906, dated April 3, 2013 between Republic Exploration LLC, Juneau Exploration, L.P. and Contango Operators, Inc. (filed as Exhibit 10.81 to the Company's report on Form 10-K for the fiscal year ended June 30, 2013, as filed with the Securities and Exchange Commission on August 29, 2013, and incorporated by reference herein).
10.17		Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto dated October 1, 2013 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated as of October 1, 2013, as filed with the Securities and Exchange Commission on October 2, 2013, and incorporated by reference herein).
10.18		First Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.1 to the Company's report on Form 8-K dated as of April 11, 2014, as filed with the Securities and Exchange Commission on April 15, 2014, and incorporated by reference herein).
10.19		Second Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.1 to the Company's report on Form 8-K dated as of October 28, 2014, as filed with the Securities and Exchange Commission on October 31, 2014, and incorporated by reference herein).
10.20		Third Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended March 31, 2016, as filed with the Securities and Exchange Commission on May 9, 2016, and incorporated by reference herein).
10.21		Fourth Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.21 to the Company's report on Form 10-K for the fiscal year ended December 31, 2017, as filed with the Securities and Exchange Commission on March 9, 2018, and incorporated by reference herein).
10.22		Fifth Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders signatory thereto (filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended June 30, 2018, as filed with the Securities and Exchange Commission on August 8, 2018, and incorporated by reference herein).
10.23		Sixth Amendment to Credit Agreement dated as of November 2, 2018 among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.5 to the Company's report on Form 10-Q for the quarter ended September 30, 2018, as filed with the Securities and Exchange Commission on November 7, 2018, and incorporated by reference herein).
10.24	*	Contango Oil & Gas Company Director Compensation Plan (filed as Exhibit 10.4 to the Company's report on Form 10-Q for the quarter ended March 21, 2017, as filed with the Securities and Exchange Commission on May 10, 2017, and incorporated by reference herein).
10.25	*	Form of Contango Oil and Gas Company Stock Award Agreement (employees) (filed as Exhibit 10.7 to the Company's report on Form 10-Q for the quarter ended September 30, 2016, as filed with the Securities and Exchange Commission on November 3, 2016, and incorporated by reference herein).
10.26	*	Form of Contango Oil and Gas Company Stock Award Agreement (executives) (filed as Exhibit 10.8 to the Company's report on Form 10-Q for the quarter ended September 30, 2016, as filed with the Securities and Exchange Commission on November 3, 2016, and incorporated by reference herein).

10.27	Separation Letter Agreement by Contango Oil & Gas Company and Allan D. Keel dated August 14, 2018 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 14, 2018, as filed with the Securities and Exchange Commission on August 15, 2018 and incorporated by reference herein).
10.28	Cooperation Agreement by Contango Oil & Gas Company and Allan D. Keel dated August 14, 2018 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 14, 2018, as filed with the Securities and Exchange Commission on August 15, 2018 and incorporated by reference herein).

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Exhibit Number	Description
10.29	Separation Agreement and Release of Claims by Contango Oil & Gas Company and Allan D. Keel dated October 9, 2018 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated October 9, 2018, as filed with the Securities and Exchange Commission on October 12, 2018 and incorporated by reference herein).
21.1	List of Subsidiaries. †
21.2	Organizational Chart. †
23.1	Consent of William M. Cobb & Associates, Inc. †
23.2	Consent of Netherland, Sewell & Associates, Inc. †
23.3	Consent of W.D. Von Gonten & Co. †
23.4	Consent of Grant Thornton LLP. †
24.1	Powers of Attorney (included on signature page). †
31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. ††
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. ††
99.1	Report of William M. Cobb & Associates, Inc. †
99.2	Report of Netherland, Sewell & Associates. †
99.3	Report of W.D. Von Gonten and Company. †

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* Indicates a management contract or compensatory plan or arrangement

† Filed herewith

† † Furnished herewith

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONTANGO OIL & GAS COMPANY

By:	/s/ WILKIE S. COLYER	Date: March 18, 2019
	Wilkie S. Colyer President and Chief Executive Officer	

POWER OF ATTORNEY

Know all men by these presents, that the undersigned constitutes and appoints Wilkie S. Colyer and E. Joseph Grady as his true and lawful attorneys-in-fact and agent, with full power of substitution for him and in his name, place and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ WILKIE S. COLYER Wilkie S. Colyer	President and Chief Executive Officer (principal executive officer) and Director	March 18, 2019
/s/ E. JOSEPH GRADY E. Joseph Grady	Chief Financial Officer (principal financial officer) and Chief Accounting Officer (principal accounting officer)	March 18, 2019
/s/ JOSEPH J. ROMANO Joseph J. Romano	Director	March 18, 2019
/s/ B. A. BERILGEN B. A. Berilgen	Director	March 18, 2019
/s/ B. JAMES FORD B. James Ford	Director	March 18, 2019

/s/ JOHN C. GOFF John C. Goff	Director	March 18, 2019
/s/ ELLIS L. MCCAIN Ellis L. McCain	Director	March 18, 2019
/s/ CHARLES M. REIMER Charles M. Reimer	Director	March 18, 2019

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Contango Oil & Gas Company

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Contango Oil & Gas Company (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, cash flows, and shareholders' equity for each of the two years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 18, 2019 expressed an unqualified opinion thereon.

Going concern

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has $60.0 million outstanding under their Credit Facility, which matures on October 1, 2019. These conditions, along with other matters as set forth in Note 2, raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/ s / GRANT THORNTON LLP

We have served as the Company's auditor since 2002.

Houston, Texas

March 18, 2019

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	December 31, 2018	December 31, 2017
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	11,531	13,059
Prepaid expenses	1,303	1,892
Current derivative asset	4,600	822
Total current assets	17,434	15,773
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,095,417	1,239,662
Unproved properties	34,612	35,243
Other property and equipment	1,314	1,272
Accumulated depreciation, depletion and amortization	(898,169)	(930,220)
Total property, plant and equipment, net	233,174	345,957
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	5,743	18,464
Deferred tax asset	424	424
Other	357	835
Total other non-current assets	6,524	19,723
TOTAL ASSETS	$ 257,132	$ 381,453
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 39,506	$ 46,755
Current derivative liability	422	1,765
Current asset retirement obligations	1,329	2,017
Current portion of long-term debt	60,000	—
Total current liabilities	101,257	50,537
NON-CURRENT LIABILITIES:		
Long-term debt	—	85,380
Long-term derivative liability	—	300
Asset retirement obligations	12,168	20,388
Other long term liabilities	3,318	248
Total non-current liabilities	15,486	106,316
Total liabilities	116,743	156,853
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
SHAREHOLDERS’ EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 39,617,442 shares issued and 34,158,492 shares outstanding at December 31, 2018, 30,873,470 shares issued and 25,505,715 shares outstanding at December 31,	1,573	1,223

2017		
Additional paid-in capital	339,981	302,527
Treasury shares at cost (5,458,950 shares at December 31, 2018 and 5,367,755 shares at December 31, 2017)	(129,030)	(128,583)
Retained earnings (deficit)	(72,135)	49,433
Total shareholders’ equity	140,389	224,600
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$ 257,132	$ 381,453

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Year Ended December 31, 2018	2017
REVENUES:		
Oil and condensate sales	$ 34,413	$ 25,347
Natural gas sales	29,824	41,317
Natural gas liquids sales	12,850	11,881
Total revenues	77,087	78,545
EXPENSES:		
Operating expenses	25,552	27,183
Exploration expenses	1,637	1,106
Depreciation, depletion and amortization	41,657	47,215
Impairment and abandonment of oil and gas properties	103,732	2,395
General and administrative expenses	24,157	24,161
Total expenses	196,735	102,060
OTHER INCOME (EXPENSE):		
Gain (loss) from investment in affiliates (net of income taxes)	(12,721)	2,697
Gain from sale of assets and return on investments	13,224	2,280
Interest expense	(5,548)	(4,100)
Gain on derivatives, net	1,939	3,325
Other income	1,306	1,275
Total other income (expense)	(1,800)	5,477
NET LOSS BEFORE INCOME TAXES	(121,448)	(18,038)
Income tax benefit (provision)	(120)	395
NET LOSS ATTRIBUTABLE TO COMMON STOCK	$ (121,568)	$ (17,643)
NET LOSS PER SHARE:		
Basic	$ (4.69)	$ (0.71)
Diluted	$ (4.69)	$ (0.71)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
Basic	25,945	24,686
Diluted	25,945	24,686

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	(121,568)	(17,643)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	41,657	47,215
Impairment of natural gas and oil properties	103,164	1,785
Exploration recovery	—	(232)
Deferred income taxes	—	(424)
Gain on sale of assets	(13,224)	(2,321)
Loss (gain) from investment in affiliates	12,721	(2,697)
Stock-based compensation	4,766	6,100
Unrealized gain on derivative instruments	(5,421)	(2,204)
Changes in operating assets and liabilities:		
Decrease in accounts receivable & other	1,316	3,914
Decrease (increase) in prepaid expenses	589	(105)
Increase (decrease) in accounts payable & advances from joint owners	(2,433)	450
Increase (decrease) in other accrued liabilities	(1,209)	1,353
Increase in income taxes receivable, net	—	(332)
Increase (decrease) in income taxes payable, net	40	(252)
Other	3,079	79
Net cash provided by operating activities	$ 23,477	$ 34,686
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (58,947)	$ (66,571)
Additions to furniture & equipment	$ (42)	$ (42)
Sale of furniture and equipment	—	12
Sale of oil and gas properties	27,805	1,151
Sale of energy credits	497	—
Net cash used in investing activities	$ (30,687)	$ (65,450)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under Credit Facility	$ 236,611	$ 239,514
Repayments under Credit Facility	(261,992)	(208,488)
Net proceeds from equity offering	33,038	—
Purchase of treasury stock	(447)	(262)
Net cash provided by financing activities	$ 7,210	$ 30,764
NET DECREASE IN CASH AND CASH EQUIVALENTS	$ —	$ —
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ —

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(in thousands, expect share amounts)

	Common Stock Shares	Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
Balance at December 31, 2016	25,238,600	$ 1,211	$ 296,439	$ (128,321)	$ 67,076	$ 236,405
Treasury shares at cost	(48,368)	—	—	(262)	—	(262)
Restricted shares activity	315,483	12	(12)	—	—	—
Stock-based compensation	—	—	6,100	—	—	6,100
Net loss	—	—	—	—	(17,643)	(17,643)
Balance at December 31, 2017	25,505,715	$ 1,223	$ 302,527	$ (128,583)	$ 49,433	$ 224,600
Equity offering	8,596,068	344	32,694	—	—	33,038
Treasury shares at cost	(91,195)	—	—	(447)	—	(447)
Restricted shares activity	147,904	6	(6)	—	—	—
Stock-based compensation	—	—	4,766	—	—	4,766
Net loss	—	—	—	—	(121,568)	(121,568)
Balance at December 31, 2018	34,158,492	$ 1,573	$ 339,981	$ (129,030)	$ (72,135)	$ 140,389

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, “Contango” or the “Company”) is a Houston, Texas based, independent oil and natural gas company. The Company’s business is to maximize production and cash flow from its 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.

Since 2016, the Company has been focused on the development of its Southern Delaware Basin acreage in Pecos County, Texas (“Bullseye”). As of December 31, 2018, the Company was producing from twelve wells over its 15,400 gross (6,500 net) acre position, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. In December 2018, the Company purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of its existing acreage (“NE Bullseye”) for approximately $7.5 million. The Company 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. The Company currently expects the Bullseye and NE Bullseye to be the primary focus of its drilling program for 2019. Throughout all this, the Company will continue to identify opportunities for cost reductions and operating efficiencies in all areas of its operations, while also searching for new resource acquisition opportunities.

As the Company continues to expand its presence in the Southern Delaware Basin, it has begun to sell small non-core assets to allow the Company to focus on West Texas. These asset sales provide some immediate liquidity and improve the Company’s balance sheet by removing potential asset retirement obligations. Beginning in 2016, the Company sold all of its Colorado assets for approximately $5.0 million. Then in 2018, the Company sold some 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. The Company also sold its offshore well at Vermilion 170 in exchange for the buyer’s assumption of the plugging and abandonment liability for the well and a retained overriding royalty interest (“ORRI”) in the well and in any future wells that produce through this platform.

Additionally, the Company has (i) a 37% equity investment in Exaro Energy III LLC (“Exaro”) that is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; (ii) operated properties producing from various conventional formations in various counties along the Texas Gulf Coast; and (iii) operated producing properties in the Haynesville Shale, Mid Bossier and James Lime formations in East Texas.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Company’s consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. All wholly-owned subsidiaries are consolidated.

Liquidity and Going Concern

Over the past few months, the Company has been in discussions with its current lenders and other sources of capital regarding a possible refinancing and/or replacement of its existing revolving credit facility with the Royal Bank of Canada (the “Credit Facility”), which matures on October 1, 2019. The refinancing or replacement of the Credit Facility could be made in conjunction with an issuance of unsecured or non-priority secured debt or preferred or common equity, non-core property monetization, potential monetization of certain midstream and/or water handling facilities, etc. or a combination of the foregoing. These discussions have included a possible new, replacement or extended credit facility that would be expected to provide additional borrowing capacity for future capital expenditures. 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. These conditions

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raise substantial doubt about the Company’s ability to continue as a going concern. However, the accompanying financial statements have been prepared assuming the Company will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The accompanying 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 the Company be unable to continue as a going concern.

Other Investments

The Company has two seats on the board of directors of Exaro and has significant influence, but not control, over the company. As a result, the Company's 37% ownership in Exaro is accounted for using the equity method. Under the equity method, the Company's proportionate share of Exaro's net income increases the balance of its investment in Exaro, while a net loss or payment of dividends decreases its investment. In the consolidated statement of operations, the Company’s proportionate share of Exaro's net income or loss is reported as a single line-item in Gain (loss) from investment in affiliates (net of income taxes).

Use of Estimates

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

Revenue Recognition

Adoption of ASC 606

As of January 1, 2018 the Company adopted Accounting Standards Codification Topic 606 – Revenue from Contracts with Customers (“ASC 606”), which supersedes the revenue recognition requirements and industry-specific guidance under Accounting Standards Codification Top 605 – Revenue Recognition (“ASC 605”). The Company adopted ASC 606 using the modified retrospective method which allows the Company to apply the new standard to all new contracts entered into after December 31, 2017 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance prior to December 31, 2017. The Company identified no material impact on its historical revenues upon initial application of ASC 606, and as such has not recognized any cumulative catch-up effect to the opening balance of the Company’s shareholders’ equity as of January 1, 2018. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

Revenue from Contracts with Customers

Sales of oil, condensate, natural gas and natural gas liquids (“NGLs”) are recognized at the time control of the products are transferred to the customer. Based upon the Company’s current purchasers’ past experience and expertise in the market, collectability is probable, and there have not been payment issues with the Company’s purchasers over the past year or currently. Generally, the Company’s gas processing and purchase agreements indicate that the processors take control of the gas at the inlet of the plant and that control of residue gas is returned to the Company at the outlet of the plant. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs. The Company delivers oil and condensate to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product.

When sales volumes exceed the Company’s entitled share, a production imbalance occurs. If production imbalance exceeds the Company’s share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. Production imbalances have not had and currently do not have a material impact on the financial statements, and this did not change with the adoption of ASC 606.

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Transaction Price Allocated to Remaining Performance Obligations

Generally, the Company’s contracts have an initial term of one year or longer but continue month to month unless written notification of termination in a specified time period is provided by either party to the contract. The Company has used the practical expedient in ASC 606 which states that the Company is not required to disclose that transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligation is not required.

Contract Balances

The Company receives purchaser statements from the majority of its customers but there are a few contracts where the Company prepares the invoice. Payment is unconditional upon receipt of the statement or invoice. Accordingly, the Company’s product sales contracts do not give rise to contract assets or liabilities under ASC 606. The majority of the Company’s contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and supply and demand conditions. The price of these commodities fluctuates to remain competitive with supply.

Prior Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements may not be received for 30 to 90 days after the date production is delivered, and therefore the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences between the Company’s estimates and the actual amounts received for product sales are generally recorded in the following month that payment is received. Any differences between the Company’s revenue estimates and actual revenue received historically have not been significant. The Company has internal controls in place for its revenue estimation accrual process.

Impact of Adoption of ASC 606

The Company has reviewed all of its natural gas, NGLs, residue gas, condensate and crude oil sales contracts to assess the impact of the provisions of ASC 606. Based upon the Company’s review, there were no required changes to the recording of residue gas or condensate and crude oil contracts. Certain NGL and natural gas contracts would require insignificant changes to the recording of transportation, gathering and processing fees as net to revenue or as an expense. The Company concluded that these minor changes were not material to its operating results on a quantitative or qualitative basis. Therefore, there was no impact to its results of operations for the twelve months ended December 31, 2018. The Company has modified procedures to its existing internal controls relating to revenue by reviewing for any significant increase in sales level, primarily on gas processing or gas purchasing contracts, on a quarterly basis to monitor the significance of gross revenue versus net revenue and expenses under ASC 606. As under previous revenue guidance, the Company will continue to review all new or modified revenue contracts on a quarterly basis for proper treatment.

Cash Equivalents

Cash equivalents are considered to be highly liquid investment grade debt investments having an original maturity of 90 days or less. As of December 31, 2018, the Company had no cash and cash equivalents, as cash balances at the end of each day are transferred to reduce outstanding debt under the Company’s revolving Credit Facility to minimize debt service costs. Under the Company’s cash management system, checks issued but not yet presented to banks by the payee frequently result in book overdraft balances for accounting purposes and are classified in accounts payable in the consolidated balance sheets. At December 31, 2018, accounts payable included $4.8 million in outstanding checks that had not been presented for payment. At December 31, 2017, accounts payable included $2.3 million in outstanding checks that had not been presented for payment.

Accounts Receivable

The Company sells natural gas and crude oil to a limited number of customers. In addition, the Company participates with other parties in the operation of natural gas and crude oil wells. Substantially all of the Company’s accounts receivables are due from either purchasers of natural gas and crude oil or participants in natural gas and crude oil wells for which the Company serves as the operator. Generally, operators of natural gas and crude oil properties have the right to offset future revenues against unpaid charges related to operated wells.

The allowance for doubtful accounts is an estimate of the losses in the Company’s accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions and other pertinent factors. Amounts deemed uncollectible are charged to the allowance.

Accounts receivable allowance for bad debt was $1.0 and $0.8 million as of December 31, 2018 and 2017, respectively. At December 31, 2018 and 2017, the carrying value of the Company’s accounts receivable approximated fair value.

Oil and Gas Properties - Successful Efforts

The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. Depreciation, depletion and amortization is calculated on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other capitalized costs amortized over proved developed reserves.

Depreciation, depletion and amortization ("DD&A") of capitalized drilling and development costs of producing natural gas and crude oil properties, including related support equipment and facilities net of salvage value, are computed using the unit of production method on a field basis based on total estimated proved developed natural gas and crude oil reserves. Amortization of producing leaseholds is based on the unit of production method using total estimated proved reserves. Upon sale or retirement of properties, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least annually. Revisions are accounted for prospectively as changes in accounting estimates.

Other property and equipment are depreciated using the straight-line method over their estimated useful lives which range between three and 13 years.

Impairment of Oil and Gas Properties

Pursuant to GAAP, when circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows, based on the Company’s estimate of future reserves, natural gas and oil prices, operating costs and production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. For the year ended December 31, 2018, the Company recorded an impairment expense of approximately $101.9 million related to proved properties. Included in proved property impairment expense for the current year was $61.7 million related to the impairment of the carrying costs of its 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 the Company's Eugene Island 11 field. In 2018, the Company also recognized onshore proved property impairment expense of $40.2 million, of which $24.9 million was related to certain of its 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 the Company's Wyoming and certain South Texas assets. See Note 4 – "Acquisitions and Dispositions" for further information regarding the property dispositions. For the year ended December 31, 2017, the Company recorded an impairment expense of approximately $0.3 million related to its proved properties.

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Unproved properties are reviewed quarterly to determine if there has been an impairment of the carrying value, with any such impairment charged to expense in the period. During the year ended December 31, 2018, the Company recognized impairment expense of approximately $1.3 million related to unproved properties due to expiring leases. During the year ended December 31, 2017, the Company recognized impairment expense of approximately $1.5 million for the partial impairment of two unused offshore platforms that were sold during the year.

Asset Retirement Obligations

Asset Retirement and Environmental Obligations (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records an asset retirement obligation ("ARO") to reflect the Company's legal obligation related to future plugging and abandonment of its oil and natural gas wells, platforms and associated pipelines and equipment. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells, platforms, and associated pipelines and equipment as these obligations are incurred. The liability is accreted to its present value each period and the capitalized cost is depleted over the useful life of the related asset. The accretion expense is included in depreciation, depletion and amortization expense.

The estimated liability is based on historical experience in plugging and abandoning wells. The estimated remaining lives of the wells is based on reserve life estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate, changes in the remaining lives of the wells or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, the Company recognizes a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs. This gain or loss on abandonment is included in impairment and abandonment of oil and gas properties expense. See Note 11 - "Asset Retirement Obligation" for additional information.

Income Taxes

The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (ii) operating loss and tax credit carryforwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when, based upon management's estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. The Company reviews its tax positions quarterly for tax uncertainties. The Company did not have significant uncertain tax positions as of December 31, 2018. Except as described below with respect to Section 382 Ownership Change, the amount of unrecognized tax benefits did not materially change from December 31, 2017. The amount of unrecognized tax benefits may change in the next twelve months; however, the Company does not expect the change to have a significant impact on its financial position or results of operations. The Company includes interest and penalties in interest income and general and administrative expenses, respectively, in its statement of operations.

The Company files income tax returns in the United States and various state jurisdictions. The Company’s federal tax returns for 1999 – 2017, and state tax returns for 2011 – 2017, remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed.

Concentration of Credit Risk

Substantially all of the Company’s accounts receivable result from natural gas and oil sales or joint interest billings to a limited number of third parties in the natural gas and oil industry. This concentration of customers and joint interest owners may impact the Company’s overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. See Note 3 - "Concentration of Credit Risk" for additional information.

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Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt. During the year ended December 31, 2013, the Company initially incurred $2.2 million of debt issuance costs relating to the Credit Facility entered into in conjunction with the merger with Crimson Exploration, Inc. The debt issuance costs were to be amortized over the original four year term of the credit line. In connection with the Credit Facility amendment in May 2016, the Company incurred an additional $1.0 million of debt issuance costs. As of December 31, 2018, the remaining balance of these debt issuance costs was $0.4 million, which will be amortized through October 1, 2019, with amortization expense included in the DD&A line item in the Company's income statement for the years ended December 31, 2018 and 2017.

Stock-Based Compensation

The Company applies the fair value based method to account for stock based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the requisite service period, which generally aligns with the award vesting period. The Company classifies the benefits of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows. The fair value of each restricted stock award is estimated as of the date of grant. The fair value of the Performance Stock Units is estimated as of the date of grant using the Monte Carlo simulation pricing model.

Inventory

Inventory primarily consists of casing and tubing which will be used for drilling or completion of wells. Inventory is recorded at the lower of cost or market using specific identification method.

Derivative Instruments and Hedging Activities

The Company accounts for its derivative activities under the provisions of ASC 815, Derivatives and Hedging (ASC 815). ASC 815 establishes accounting and reporting requirements that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, the Company hedges a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction using variable to fixed swaps and collars. The Company elected to not designate any of its derivative positions for hedge accounting. Accordingly, the net change in the mark-to-market valuation of these positions as well as all payments and receipts on settled derivative contracts are recognized in "Gain on derivatives, net" on the consolidated statements of operations for the years ended December 31, 2018 and 2017. Derivative instruments with settlement dates within one year are included in current assets or liabilities, whereas derivative instruments with settlement dates exceeding one year are included in non-current assets or liabilities. The Company calculates a net asset or liability for current and non-current derivative instruments for each counterparty based on the settlement dates within the respective contracts. See Note 6 - "Derivative Instruments" for additional information.

Subsidiary Guarantees

Contango Oil & Gas Company, as the parent company (the “Parent Company”), filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Crimson Exploration Inc., Crimson Exploration Operating, Inc., Contango Energy Company, Contango Operators, Inc., Contango Mining Company, Conterra Company, Contaro Company, Contango Alta Investments, Inc., Contango Venture Capital Corporation, Contango Rocky Mountain Inc. and any other of the Company's future subsidiaries specified in the prospectus supplement (each a "Subsidiary Guarantor") are Co-Registrants with the Parent Company under the registration statement, and the registration statement also registered guarantees of debt securities by the Subsidiary Guarantors. The Subsidiary Guarantors are wholly-owned by the Parent Company, either directly or indirectly, and any guarantee by the Subsidiary Guarantors will be full and unconditional. The Parent Company has no assets or operations independent of the Subsidiary Guarantors, and there are no significant restrictions upon the ability of the Subsidiary Guarantors to distribute funds to the Parent Company. The Parent Company has one other wholly-owned subsidiary that is inactive. Finally, the Parent Company's wholly-owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

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Recent Accounting Pronouncements

Leases: In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02: Leases (Topic 842) (ASU 2016-02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP treatment of leases and that proposed in ASU 2016-02 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize a right-of-use asset and lease liability arising from such operating leases on the balance sheet.

ASU 2016-02 contains several optional practical expedients, one of which is referred to as the "package of three practical expedients". The expedients must be taken together and allow entities to: (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. The Company has elected to apply this practical expedient package to all of its leases. The Company has also chosen to implement the "short-term accounting policy election" which allows the Company to not include leases with an initial term of 12 months or less on the balance sheet.

For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company adopted this standard on January 1, 2019, and the impact of adoption is immaterial.

Other: In August 2016, the FASB issued ASU No. 2016-15: Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments. The main objective of this update is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The eight cash flow updates relate to the following issues: 1) debt prepayment or debt extinguishment costs; 2) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; 3) contingent consideration payments made after a business combination; 4) proceeds from the settlement of insurance claims; 5) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies; 6) distributions received from equity method investees; 7) beneficial interest in securitization transactions; and 8) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The provisions of this update are not expected to have a material impact on the Company's presentation of cash flows.

In January 2017, the FASB issued ASU No. 2017-01: Business Combinations (Topic 805) Clarifying the Definition of a Business (ASU 2018-01). The amendments in this update are intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill and consolidation. Public business entities should apply the amendments in this update to annual periods beginning after December 15, 2018, including interim periods within those periods. The amendments in this update should be applied prospectively on or after the effective date. No disclosures are required at transition. The provisions of this update are not expected to have a material impact on the Company’s financial position or results of operations.

In August 2018, the FASB issued ASU 2018-13 – Fair Value Measurement (Topic 820). The amendments in ASU 2018-13 modify the disclosure requirements on fair value measurements in Topic 820. The amendments in this update are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The provisions of this update are not expected to have a material impact on the Company’s financial position or results of operations.

3. Concentration of Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. The largest purchaser of the Company’s production for the year ended December 31, 2018 was ConocoPhillips Company (36.9%). The Company’s sales to this company are not secured with letters of credit and in the event of non-payment, the Company

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could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on the Company’s financial position. There are numerous other potential purchasers of the Company’s production.

4. Acquisitions and Dispositions

Southern Delaware Basin Acquisition

In July 2016, the Company purchased approximately 12,100 gross undeveloped acres (approximately 5,000 net) acres (“Bullseye”) in the Southern Delaware Basin of Texas for up to $25 million. The purchase price was comprised of $10 million in cash paid on July 26, 2016, plus $10 million in carried well costs over the first six wells. Additionally, contingent upon success, $5 million in spud bonuses is to be paid by the Company ratably over the following 14 wells drilled, which would increase the total consideration paid by the Company to $25 million. As of December 31, 2018, the Company had paid all $10 million of the carried well costs and $3.7 million in spud bonuses. In December 2018, the Company purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of its existing acreage (“NE Bullseye”) for approximately $7.5 million. The Company 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.

North Bob West Property Sale

Effective February 1, 2017, the Company sold to a third party all of its assets in the North Bob West area and its operated assets in the Escobas area, both located in Southeast Texas, for a cash purchase price of $650,000. The Company recorded a net gain of $2.9 million after removal of the asset retirement obligations associated with the sold properties.

Karnes County Property Sale

On March 28, 2018, the Company sold its operated Eagle Ford Shale assets located in Karnes County, Texas for a cash purchase price of $21.0 million. The Company recorded a net gain of $9.5 million.

Starr County Property Sale

On May 25, 2018, the Company sold its non-operated assets located in Starr County, Texas for a cash purchase price of $0.6 million. The Company recorded a gain of $1.3 million after removal of the asset retirement obligations associated with the sold properties.

Liberty and Hardin County Property Sale

On September 11, 2018, the Company entered into a definitive agreement to divest certain of its non-core assets in Liberty and Hardin counties in Southeast Texas. As a result of the sale, the Company reduced the value of the assets to their purchase price and recorded an impairment of approximately $12.8 million during the three months ended September 30, 2018 in “Impairment and abandonment of oil and gas properties” in the Company’s consolidated statement of operations. The sale was completed on November 2, 2018 for cash proceeds of $6.0 million.

Elm Hill Property Sale

On December 4, 2018, the Company sold its non-core assets located in Fayette, Gonzales, Caldwell and Bastrop counties in South Texas for a cash purchase price of $85,000. The Company recorded a gain of approximately $175,000 after removal of the asset retirement obligations associated with the sold properties.

Vermilion 170 Property Sale

Effective December 1, 2018, the Company sold its offshore Vermilion 170 well in exchange for a continuing ORRI in the Vermilion 170 well, the buyer’s assumption of the plugging and abandonment liability for the well, platform and associated pipeline and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through this platform.

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Brooks and Zapata County Property Sale

Effective December 31, 2018, the Company sold its assets located primarily in Brooks and Zapata counties in South Texas for a cash purchase price of $150,000. As a result of this planned sale, the Company reduced the value of the assets to their fair value and recorded an impairment of approximately $12.1 million included in “Impairment and abandonment of oil and gas properties” in the Company’s consolidated statement of operations.

5. Fair Value Measurements

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

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

Derivatives are recorded at fair value at the end of each reporting period. The Company records the net change in the fair value of these positions in "Gain on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 6 - "Derivative Instruments" for additional discussion of derivatives.

During the year ended December 31, 2018, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which were believed to have a minimal credit risk. As such, the Company was exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company did not anticipate any nonperformance. The counterparties to the Company's current and previous derivative contracts are lenders in the Company's Credit Facility. The Company did not post collateral under any of these contracts as they were secured under the Credit Facility.

Estimates of the fair value of financial instruments are made in accordance with the requirements of ASC 825, Financial Instruments. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Credit Facility approximates carrying value because the interest rate approximates current market rates and are re-set at least every three months. See Note 12 - "Indebtedness" for further information.

Fair value estimates used for non-financial assets are evaluated at fair value on a non-recurring basis include oil and gas properties evaluated for impairment when facts and circumstances indicate that there may be an impairment. If the unamortized cost of properties exceeds the undiscounted cash flows related to the properties, the value of the properties is compared to the fair value estimated as discounted cash flows related to the risk-adjusted proved, probable and possible reserves related to the properties. Fair value measurements based on these inputs are classified as Level 3.

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Impairments

Contango tests proved oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. The Company estimates the undiscounted future cash flows expected in connection with the oil and gas properties on a field by field basis and compares such future cash flows to the unamortized capitalized costs of the properties. If the estimated future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. Because these significant fair value inputs are typically not observable, impairments of long-lived assets are classified as a Level 3 fair value measure.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period.

Asset Retirement Obligations

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, estimated future plugging and abandonment costs and expected lives of the related reserves. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3 at inception.

6. Derivative Instruments

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

As of December 31, 2018, the Company’s natural gas and oil derivative positions consisted of “swaps” and “costless collars”. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract, and a purchased put, which establishes a minimum price. A sold put option limits the exposure of the counterparty's risk should the price fall below the strike price. Sold put options limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold.

It is the Company's practice to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The counterparties to the Company's current and previous derivative contracts are lenders or affiliates of lenders in the Credit Facility. The Company does not post collateral under any of these contracts as they are secured under the Credit Facility.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in "Gain on derivatives, net" on the consolidated statements of operations. See Note 5 – “Fair Value Measurements” for additional information.

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The Company had the following financial derivative contracts in place as of December 31, 2018:

Commodity	Period	Derivative	Volume/Month	Price/Unit (1)	Fair Value
Natural Gas	Jan 2019 - March 2019	Swap	600,000 MMBtus	$ 3.21 (1)	121
Natural Gas	April 2019 - July 2019	Swap	600,000 MMBtus	$ 2.75 (1)	109
Natural Gas	Aug 2019 - Oct 2019	Swap	100,000 MMBtus	$ 2.75 (1)	3
Natural Gas	Nov 2019 - Dec 2019	Swap	500,000 MMBtus	$ 2.75 (1)	(116)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)	(27)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$ 52.00 - 59.45 (3)	233
Oil	Jan 2019 - June 2019	Collar	12,000 Bbls	$ 70.00 - 76.25 (3)	1,569
Oil	Jan 2019 - July 2019	Swap	6,000 Bbls	$ 66.10 (3)	811
Oil	July 2019	Swap	12,000 Bbls	$ 72.10 (3)	288
Oil	Aug 2019 - Oct 2019	Swap	9,000 Bbls	$ 72.10 (3)	635
Oil	Nov 2019 - Dec 2019	Swap	12,000 Bbls	$ 72.10 (3)	552
			Total net fair value of derivative instruments		$ 4,178

(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.

The Company had the following financial derivative contracts in place as of December 31, 2017:

Commodity	Period	Derivative	Volume/Month	Price/Unit	Fair Value
Natural Gas	Jan 2018 - July 2018	Swap	370,000 MMBtus	$ 3.07 (1)	678
Natural Gas	Aug 2018 - Oct 2018	Swap	70,000 MMBtus	$ 3.07 (1)	56
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$ 3.07 (1)	89
Oil	Jan 2018 - June 2018	Swap	20,000 Bbls	$ 56.40 (2)	(994)
Oil	July 2018 - Oct 2018	Collar	20,000 Bbls	$ 52.00 - 56.85 (2)	(544)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$ 52.00 - 56.85 (2)	(173)
Oil	Jan 2018 - Dec 2018	Collar	2,000 Bbls	$ 52.00 - 58.76 (3)	(55)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)	(300)
			Total net fair value of derivative instruments		$ (1,243)

(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.

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The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2018 (in thousands).

	Gross	Netting (1)	Total
Assets	$ 4,600	$ —	$ 4,600
Liabilities	$ (422)	$ —	$ (422)

(1) Represents counterparty netting under agreements governing such derivatives.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2017 (in thousands):

	Gross	Netting (1)	Total
Assets	$ 1,188	$ (1,188)	$ —
Liabilities	$ (2,431)	$ 1,188	$ (1,243)

(1) Represents counterparty netting under agreements governing such derivatives.

The following table summarizes the effect of derivative contracts on the Consolidated Statements of Operations for the years ended December 31, 2018 and 2017 (in thousands):

	Year Ended December 31,	
Contract Type	2018	2017
Crude oil contracts	$ (2,969)	$ 861
Natural gas contracts	(513)	260
Realized gain (loss)	$ (3,482)	$ 1,121
Crude oil contracts	$ 6,126	$ (2,065)
Natural gas contracts	(705)	4,269
Unrealized gain	$ 5,421	$ 2,204
Gain on derivatives, net	$ 1,939	$ 3,325

7. Stock Based Compensation

As of December 31, 2018, the Company had in place the Contango Oil & Gas Company Second Amended and Restated 2009 Incentive Compensation Plan (“the Second Amended 2009 Plan”) which allows for stock options, restricted stock or performance stock units to be awarded to officers, directors and employees as a performance-based award.

Second Amended and Restated 2009 Incentive Compensation Plan

On March 21, 2017, the Company's board of directors (the "Board") amended and restated the Company's then existing incentive compensation plan through the adoption of the Second Amended 2009 Plan. The Second Amended 2009 Plan provides for both cash awards and equity awards to officers, directors, employees or consultants of the Company. Awards made under the Second Amended 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Under the terms of the Second Amended 2009 Plan, shares of the Company's common stock may be issued for plan awards. Stock options under the Second Amended 2009 Plan must have an exercise price of each option equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant officers and employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options granted

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generally expire after five or ten years. The vesting schedule for all equity awards varies from immediately to over a four-year period. As of December 31, 2018, the Company had approximately 1.6 million shares of equity awards available for future grant under the Second Amended 2009 Plan, assuming Performance Stock Units are settled at 100% of target.

Effective January 1, 2014, the Company implemented performance-based long-term bonus plans under the 2009 Plan for the benefit of all employees through a Cash Incentive Bonus Plan ("CIBP") and a Long-Term Incentive Plan ("LTIP"). The specific targeted performance measures under these sub-plans are approved by the Compensation Committee and/or the Board. Upon achieving the performance levels established each year, bonus awards under the CIBP and LTIP will be calculated as a percentage of base salary of each employee for the plan year. The CIBP and LTIP plan awards for each year are expected to be disbursed in the first quarter of the following year. Employees must be employed by the Company at the time that awards are disbursed to be eligible.

The CIBP awards will be paid in cash while LTIP awards will consist of restricted common stock, performance stock units and/or stock options. The number of shares of restricted common stock and the number of shares underlying the stock options granted will be determined based upon the fair market value of the common stock on the date of the grant.

2005 Stock Incentive Plan

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

Stock Options

A summary of stock options as of and for the years ended December 31, 2018 and 2017 is presented in the table below (dollars in thousands, except per share data):

	Year Ended December 31,			
	2018		2017	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of the period	94,833	$ 57.69	111,905	$ 55.53
Exercised	—	$ —	—	$ —
Expired / Forfeited	(61,196)	$ 58.72	(17,072)	$ 43.50
Outstanding, end of year	33,637	$ 55.82	94,833	$ 57.69
Aggregate intrinsic value	$ —		$ —	
Exercisable, end of year	33,637	$ 55.82	94,833	$ 57.69
Aggregate intrinsic value	$ —		$ —	
Available for grant, end of the period*	1,854,588		2,002,492	
Weighted average fair value of options granted during the period	$ —		$ —	

* Excludes Performance Stock Units.

During the years ended December 31, 2018 and 2017, the Company did not issue any stock options. During the year ended December 31, 2018, 61,196 stock options previously issued were forfeited by former employees, of which 55,943 were related to the resignation of the Company's former President and CEO in September 2018. During the year ended December 31, 2017, 17,072 stock options previously issued were forfeited.

As of December 31, 2018, there were 33,637 stock options vested and exercisable under the 2005 Plan. The exercise price for such options ranges from $28.96 to $60.33 per share, with an average remaining contractual life of two years.

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as

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financing cash flows. For the years ended December 31, 2018 and 2017, there was no excess tax benefit recognized. See Note 2 – "Summary of Significant Accounting Policies".

Compensation expense related to employee stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model.

During the years ended December 31, 2018 and 2017, the Company did not recognize any stock option expense. The aggregate intrinsic value of stock options exercised/forfeited during each of the years ended December 31, 2018 and 2017 was zero.

Restricted Stock

During the year ended December 31, 2018, the Company issued 225,782 restricted stock awards from the 2009 Plan, which vest over three years, to executive officers as part of their overall 2018 compensation packages. Additionally, the Company issued 82,500 restricted stock awards from the 2009 Plan, which vest on the one-year anniversary of the date of grant, to the members of the board of directors as part of their 2018 director compensation. During the year ended December 31, 2018, 160,378 restricted stock awards were forfeited by former employees, of which 105,800 were related to the resignation of the Company's former President and CEO in September 2018. 102,573 of the shares vested in 2018 were also related to the resignation of the Company's former President and CEO in September 2018. The weighted average fair value of the restricted shares granted during the year was $3.76, with a total grant date fair value of approximately $1.2 million after adjustment for estimated weighted average forfeiture rate of 0.0%.

During the year ended December 31, 2017, the Company issued 383,376 restricted stock awards to new and existing employees, which vest over three years, plus an additional 74,325 restricted stock awards to the members of the board of directors which vest on the one-year anniversary of the date of grant. During the year ended December 31, 2017, 142,218 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $7.55, with a total grant date fair value of approximately $3.5 million after adjustment for estimated weighted average forfeiture rate of 4.8%.

Restricted stock activity as of December 31, 2018 and 2017 and for the years then ended is presented in the table below (dollars in thousands, except per share data):

	2018			2017		
	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value
Outstanding, beginning of the period	731,073	$ 10.55	$ 1,667	638,158	$ 14.22	$ 5,960
Granted	308,282	3.76	1,158	457,701	7.55	3,457
Vested	(419,356)	10.72	1,965	(222,568)	15.12	1,263
Canceled / Forfeited	(160,378)	6.49	309	(142,218)	10.23	814
Not vested, end of the period	459,621	7.26	662	731,073	10.55	1,667

The Company recognized approximately $4.8 million and $6.1 million in stock compensation expense during the years ended December 31, 2018 and 2017, respectively, for restricted shares granted to its officers, employees and directors. As of December 31, 2018, there were 459,621 shares of unvested restricted stock outstanding. An additional $1.9 million of compensation expense will be recognized over the remaining vesting period.

Performance Stock Units

Performance stock units ("PSUs") represent a contractual right to receive shares of the Company's common stock. The settlement of PSUs may range from 0% to 300% of the targeted number of PSUs stated in the agreement contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PSUs vest and settlement is determined after a three year period.

Compensation expense associated with PSUs is based on the grant date fair value of a single PSU as determined using the Monte Carlo simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the PSUs with shares of the Company's common stock after three years, the PSU awards are accounted for as equity awards, and the fair value is

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calculated on the grant date. The simulation model calculates the payout percentage based on the stock price performance over the performance period. The concluded fair value is based on the average achievement percentage over all the iterations. The resulting fair value expense is amortized over the life of the PSU award.

During the year ended December 31, 2018, the Company granted 190,782 PSUs to executive officers, as part of their overall compensation package, at a weighted average fair value of $7.69 per unit. All prices were determined using the Monte Carlo simulation model. Also during the year, 188,927 PSUs were forfeited by former employees, of which 153,127 were related to the resignation of the Company's former President and CEO in September 2018. 147,800 PSUs that were issued in 2016 expired during the year ended December 31, 2018, as the Company did not meet the performance criteria, and are available to be reissued.

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

8. Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market or through privately negotiated transactions. Purchases are made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market, and when the Company believes its stock price to be undervalued. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes. No shares were purchased during the years ended December 31, 2018 and 2017. As of December 31, 2018, the Company had $31.8 million available under the share repurchase program for future purchases.

On November 2, 2018, the Company amended its revolving Credit Facility with Royal Bank of Canada to, among other things, prevent for share repurchases subject to certain conditions. The Company is currently in compliance with these conditions.

9. Other Financial Information

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

	December 31, 2018	December 31, 2017
Accounts receivable:		
Trade receivables	$ 6,052	$ 6,565
Receivable for Alta Resources distribution	1,993	1,993
Joint interest billings	3,833	4,030
Income taxes receivable	424	424
Other receivables	223	828
Allowance for doubtful accounts	(994)	(781)

Total accounts receivable	$ 11,531	$ 13,059
Prepaid expenses and other:		
Prepaid insurance	$ 792	$ 1,177
Other	511	715
Total prepaid expenses and other	$ 1,303	$ 1,892
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 17,986	$ 18,181
Advances from partners	1,785	2,243
Accrued exploration and development	4,751	8,400
Accrued acquisition costs	4,352	—
Trade payables	3,385	9,559
Accrued general and administrative expenses	2,545	2,960
Accrued operating expenses	1,801	1,654

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Other accounts payable and accrued liabilities	2,901	3,758
Total accounts payable and accrued liabilities	$ 39,506	$ 46,755

Included in the table below is supplemental cash flow disclosures and non-cash investing activities during the years ended December 31, 2018 and 2017, in thousands:

	Year Ended December 31,	
	2018	2017
Cash payments:		
Interest payments	$ 5,656	$ 3,699
Income tax payments, net of cash refunds	81	616
Non-cash items excluded from investing activities in the consolidated statements of cash flows:		
Decrease in accrued capital expenditures	(3,649)	(9,931)

10. Investment in Exaro Energy III LLC

Through the Company’s wholly-owned subsidiary, Contaro Company (“Contaro”), the Company committed to invest up to $67.5 million in Exaro for an ownership interest of approximately 37%. The aggregate commitment of all the Exaro investors was approximately $183 million. The Company did not make any contributions during the year ended December 31, 2018 and has no plans to invest additional funds in Exaro, as the commitment to invest in Exaro expired on March 31, 2017. As of December 31, 2018, the Company had invested approximately $46.9 million. Contango’s share in the equity of Exaro at December 31, 2018 was approximately $5.7 million.

The Company's share in Exaro's results of operations recognized for the years ended December 31, 2018 and 2017 was a loss of $12.6 million, net of zero tax expense and a gain of $2.7 million, net of zero tax, respectively.

11. Asset Retirement Obligation

The Company accounts for its retirement obligation of long lived assets by recording the net present value of a liability for an asset retirement obligation (“ARO”) in the period in which it is incurred. When the liability is initially recorded, a company increases the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

Activities related to the Company’s ARO during the years ended December 31, 2018 and 2017 were as follows (in thousands):

	Year Ended December 31, 2018	2017
Balance as of the beginning of the period	$ 22,405	$ 26,926
Liabilities incurred during period	163	308
Liabilities settled during period	(1,339)	(4,503)
Accretion	960	1,056
Sales	(8,599)	(2,949)
Change in estimate	(93)	1,567
Balance as of the end of the period	$ 13,497	$ 22,405

All of the total liabilities incurred during the years ended December 31, 2018 and 2017 were related to new wells drilled during the period. All of the total liabilities settled during the years ended December 31, 2018 and 2017 were related to wells plugged and abandoned during the period.

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12. Indebtedness

Credit Facility

The Company's $500 million revolving Credit Facility with Royal Bank of Canada and other lenders (the "Credit Facility"), currently matures on October 1, 2019. The borrowing base under the facility is redetermined each November 1 and May 1. On November 2, 2018, the Company entered into the Sixth Amendment to the Credit Facility (the "Sixth Amendment"), whereby the current borrowing base was reaffirmed at $105 million and was reduced to $90 million on and after January 31, 2019 until the next scheduled redetermination date on May 1, 2019.

The Sixth Amendment also provides for, among other things: (i) reducing the letter of credit issuance commitment capacity from $20.0 million to $5.0 million; (ii) waiving compliance with the required minimum 1.00 to 1.00 Current Ratio for the fiscal quarters ended September 30, 2018 and December 31, 2018; (iii) eliminating an exception from the restriction on payment of dividends, stock repurchases or redemptions of equity for repurchases under certain circumstances; (iv) waiving advance notice and a requirement for delivery of a revised reserve report related to the Liberty and Hardin County, Texas asset sale; and (v) requires delivery to the administrative agent of internally-prepared monthly consolidated financial statements of the Company within 25 days of the end of such month.

Initially, the Company incurred $2.2 million of arrangement and upfront fees in connection with the Credit Facility which was to be amortized over the original four-year term of the facility. In May 2016, in connection with the amendment, the Company incurred an additional $1.0 million of arrangement and upfront fees. As of December 31, 2018, the remaining balance of these fees was $0.4 million, which will be amortized through October 1, 2019.

As of December 31, 2018, the Company had $60.0 million outstanding under the Credit Facility, which matures on October 1, 2019, and $1.9 million in outstanding letters of credit. As of December 31, 2017, the Company had $85.4 million outstanding under the Credit Facility and $1.9 million in outstanding letters of credit. As of December 31, 2018, borrowing availability under the Credit Facility was $43.1 million.

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

Borrowings under the Credit Facility bear interest at LIBOR, the U.S. prime rate, or the federal funds rate, plus a 2.5% to 4.0% margin, dependent upon the amount outstanding. Additionally, the Company must pay a 0.5% commitment fee regardless of the amount of the Credit Facility that is unused. Total interest expense under the Credit Facility, including commitment fees, for the years ended December 31, 2018 and 2017 was approximately $5.5 million and $4.1 million, respectively.

The Credit Facility contains restrictive covenants which, among other things, requires a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the Credit Facility agreement. As of December 31, 2018, the Company was in compliance with all of its covenants. However, the Company was 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. The Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, a going concern qualification, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events. As of December 31, 2018, the Company was in compliance with all of its covenants under the Credit Facility agreement.

Pursuit of Refinancing and Other Liquidity-Enhancing Alternatives

Over the past few months, the Company has been in discussions with its current lenders and other sources of capital regarding a possible refinancing and/or replacement of its existing 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 refinancing and/or replacement of the Credit Facility could be made in conjunction with an issuance of unsecured or non-priority secured debt or preferred or common equity, non-core property monetization, potential monetization of certain midstream and/or

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water handling facilities, etc. or a combination of the foregoing. These discussions have included a possible new, replacement or extended Credit Facility that would be expected to provide additional borrowing capacity for future capital expenditures. While the Company reviews such liquidity-enhancing alternative sources of capital, it intends to continue to minimize its drilling program capital expenditures in the Southern Delaware Basin and pursue a reduction in its borrowings under the Credit Facility, including through a reduction in cash general and administrative expenses and the possible sale of additional non-core properties.

13. Commitments and Contingencies

Contango pays delay rentals on its oil and gas leases and leases its office space and certain other equipment. The Company's corporate offices are located at 717 Texas Avenue in downtown Houston, Texas, under a lease that expires March 31, 2021.

As of December 31, 2018, minimum future lease payments for delay rentals and operating leases for Contango's fiscal years are as follows (in thousands):

Fiscal years ending December 31,	
2019	$ 958
2020	265
2021	179
2022	70
2023	69
2024 and thereafter	69
Total	$ 1,610

The amounts incurred under operating leases and delay rentals during the years ended December 31, 2018 and 2017 were approximately $5.1 million and $4.8 million, respectively.

Throughput Contract Commitment

The Company signed a throughput agreement with a third party pipeline owner/operator that constructed a natural gas gathering pipeline in the Company's Southeast Texas area that allows the Company to defray the cost of building the pipeline itself. Beginning in late 2016, the Company was unable to meet the minimum monthly gas volume deliveries through this line in its Southeast Texas area and currently forecasts it will continue to not meet the minimum throughput requirements under the agreement. Without further development in that area, the volume deficiency will continue through the expiration of the throughput commitment in March 2020. The throughput deficiency fee is paid in April of each calendar year. The Company incurred fees of $1.0 million, $1.1 million and $0.4 million during the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, the Company estimates that the net deficiency fee will be approximately $1.0 million annually for the remaining contract period, based upon forecasted production volumes from existing proved producing reserves only, assuming no future development during this commitment period. As of December 31, 2018, based upon the current commodity price market and the

Company's short term strategic drilling plans, the Company has recorded a $1.7 million loss contingency through December 31, 2019. The Company will continue to assess this commitment in light of its drilling and development plans for this area and will need to accrue an additional $240 thousand through the expiration of the throughput commitment, if there is no new development in this area.

Legal Proceedings

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

On November 16, 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The

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Company appealed the trial court's decision to the Texas Court of Appeals, and in the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court's summary decision. In the first quarter of 2018, the Company filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company continues to vigorously defend this lawsuit and has filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. The Company is awaiting a response from the Texas Supreme Court as to whether it intends to review the case. In addition, the Company is also in the process of seeking amicus briefs from industry associations whose members would be affected by the Court of Appeals' ruling.

On September 14, 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgement in the Company's favor. The plaintiff filed a motion for rehearing, which was denied in May 2018. The plaintiff has filed a petition requesting that the matter be reviewed by the Texas Supreme Court; the parties are awaiting a response from the Texas Supreme Court as to whether it intends to review the case. The Company continues to vigorously defend this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

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

Employment Agreements

On November 30, 2016, all of the Company's existing employment agreements expired through nonrenewal, and the Company and Mr. Keel, Mr. Grady, Mr. Mengle and Mr. Atkins entered into Amended and Restated Employment Agreements ("Employment Agreements"). The Employment Agreements provided for an initial term of three years for Messrs. Keel and Grady and an initial term of two years for Messrs. Mengle and Atkins. Each of the Employment Agreements will automatically renew for additional one year terms, unless Contango or the executive provides prior notice of intention not to extend the agreement. Mr. Keel's employment agreement was terminated in conjunction with the Separation Agreement entered into between the Company and Mr. Keel on August 14, 2018. The employment agreements with Mr. Mengle and Mr. Atkins expired on November 30, 2018 and were not renewed pursuant to the Company's plan to phase out the use of employment agreements.

During the term of the Employment Agreements, Mr. Keel was entitled to a base salary of $600,000 until his resignation. Mr. Grady is entitled to a base salary of $400,000, Mr. Mengle was entitled to a base salary of $300,000 and Mr. Atkins was entitled to a base salary of $310,000. The Employment Agreements provided that each executive shall participate in the Company's CIBP and LTIP. With respect to the CIBP, the Employment Agreements provide that the executives are eligible to receive an annual cash incentive bonus with a target award level of 100% for Messrs. Keel and Grady and 80% for Messrs. Mengle and Atkins, of such executive's base salary, under such terms and conditions as the Company may determine each applicable year. With respect to the LTIP, the Employment Agreements provide that the executives are eligible to participate in the Company's equity compensation plan for each calendar year in which the executive is employed by the Company, under such terms and conditions as the Company may determine in each applicable year.

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14. Net Loss Per Common Share

A reconciliation of the components of basic and diluted net loss per common share for the years ended December 31, 2018 and 2017 is presented below (in thousands):

	Year Ended December 31, 2018		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (121,568)	25,945	$ (4.69)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options, restricted stock and PSUs)	—	—	—
Net loss attributable to common stock	$ (121,568)	25,945	$ (4.69)

	Year Ended December 31, 2017		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (17,643)	24,686	$ (0.71)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options, restricted stock and PSUs)	—	—	—
Net loss attributable to common stock	$ (17,643)	24,686	$ (0.71)

The numerator for basic earnings per share is net loss attributable to common stockholders. The numerator for diluted earnings per share is net loss available to common stockholders.

Potential dilutive securities (stock options, restricted stock and PSUs) have not been considered when their effect would be antidilutive. The potentially dilutive shares would have been 1,141,707 shares and 1,282,590 shares for the years ended December 31, 2018 and 2017, respectively.

15. Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. The Company is subject to taxation in several jurisdictions, and the calculation of its tax liabilities involves dealing with uncertainties in the application of complex tax laws (including the effect of the Tax Cuts and Jobs Act of 2017) and regulations in various taxing jurisdictions.

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The Tax Cuts and Jobs Act 2017

On December 22, 2017, the United States enacted tax reform legislation known as the H.R.1, commonly referred to as the "Tax Cuts and Jobs Act" (the "Act"), resulting in significant modifications to existing law. The Company completed the accounting for the effects of the Act during 2017. The Company's financial statements for the year ended December 31, 2018 reflect certain effects of the Act which includes a reduction in the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as well as other changes. The Tax Cuts and Jobs Act of 2017 contained a significant limitation on Section 163(j) interest taken in any given tax year. As of December 31, 2018, the Company had a limitation of $5.5 million which will carry over indefinitely. The carryover is subject to any applicable Section 382 limitation (discussed below).

Actual income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate rate of 21 percent and 35 percent for the years ended December 31, 2018 and 2017, respectively, to pretax income as follows (dollars in thousands):

	Year Ended December 31,					
	2018			2017		
Provision/(benefit) at statutory tax rate	$ (25,504)	21.00	%	$ (6,314)	35.00	%
State income tax provision, net of federal benefit	120	(0.10)	%	(864)	4.79	%
Permanent differences	579	(0.48)	%	50	(0.28)	%
Stock based compensation	1,353	(1.11)	%	(361)	2.00	%
Valuation allowance	21,941	(18.07)	%	7,209	(39.96)	%
Rate change (35% to 21% fed rate)	0	0	%	35,250	(195.41)	%
Valuation allowance for remeasurement and changes relating to the Tax Cuts and Jobs Act	0	0	%	(35,674)	197.76	%
Other	1,631	(1.34)	%	309	(1.71)	%
Income tax provision /(benefit)	$ 120	(0.10)	%	$ (395)	2.19	%

The effective tax rate for the years ended December 31, 2018 and 2017 varies from the statutory rate primarily as a result of recording a valuation allowance.

The provision (benefit) for income taxes for the periods indicated are comprised of the following (in thousands):

	Year Ended December 31,	
	2018	2017
Current tax provision (benefit):		
Federal	$ —	$ (424)
State	120	453
Total	$ 120	$ 29
Deferred tax provision (benefit):		
Federal	$ —	$ (424)
State	—	—

Total	$ —	$ (424)
Total tax provision (benefit):		
Federal	$ —	$ (848)
State	120	453
Total	$ 120	$ (395)
Included in gain (loss) from investment in affiliates	$ —	$ —
Total income tax provision (benefit)	$ 120	$ (395)

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The net deferred tax is comprised of the following (in thousands):

	December 31, 2018	2017
Deferred tax assets:		
Net operating loss carryforward	$ 80,930	$ 60,464
Income tax credits	454	454
Derivative instruments	—	261
Deferred compensation	678	1,418
Oil and gas properties	—	—
Other	1,529	491
Total deferred tax assets before valuation allowance	$ 83,591	$ 63,088
Valuation allowance	(70,973)	(49,032)
Net deferred tax assets	$ 12,618	$ 14,056
Deferred tax liability:		
Oil and gas properties	$ (11,042)	$ (10,567)
Investment in affiliates	(275)	(3,065)
Derivative instruments	(877)	—
Deferred tax liability	$ (12,194)	$ (13,632)
Total net deferred tax	$ 424	$ 424

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

In assessing the realizability of deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. The Company considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the amount of deferred tax liabilities, level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, the Company believes it is not more-likely-than-not that it will realize the benefits of these deductible differences and has recorded a valuation allowance for federal and state purposes of approximately $70 million and approximately $1 million, respectively.

As of December 31, 2018, the Company had federal net operating loss (“NOL”) carryforwards of approximately $380.8 million and state NOLs of $20.4 million. The Federal NOL carryforwards occurred due to the merger with Crimson Exploration, Inc. (“Crimson”) in 2013 (the “Merger”) and subsequent taxable losses during the years 2014 through 2018 due to lower commodity prices and utilization of various elections available to the Company in expensing capital expenditures incurred in the development of oil and gas properties. Generally, these NOLs are available to reduce future taxable income and the related income tax liability subject to the limitations set forth in Internal Revenue Code

Section 382 related to changes of more than 50% of ownership of the Company’s stock by 5% or greater shareholders over a three-year period (a Section 382 Ownership Change) from the time of such an ownership change.

On November 19, 2018, the Company completed a follow-on offering (the “Offering”) of 7.5 million additional shares of common stock. Prior to December 18, 2018, the underwriters exercised their Green Shoe option purchasing an additional approximate 1.1 million shares, resulting in a total of approximately 8.6 million primary shares issued in the Offering. This issuance resulted in a Section 382 Ownership Change which limits the Company’s future ability to use its NOLs. As such, the Company is limited in use of NOLs and Section 163(j) interest expense limitations for amounts incurred prior to November 20, 2018 in an amount estimated to be approximately $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). Based on current year estimates, it is likely that a substantial portion of the Company’s pre-2018 NOL’s will expire unused as a result of these limitations. Due to the presence of the valuation allowance from prior years, this event resulted in a no net charge to earnings.

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ASC 740, Income Taxes ("ASC 740") prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. As a result of the Merger, the Company acquired certain tax positions taken by Crimson in prior years. These positions are not expected to have a material impact on results of operations, financial position or cash flows. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows (in thousands):

	Unrecognized Tax Benefits
Balance at December 31, 2017	$ 227
Additions based on tax positions related to the current year	—
Additions based on tax positions related to prior years	—
Additions due to acquisitions	—
Reductions due to a lapse of the applicable statute of limitations	—
Change in rate due to remeasurement	—
Balance at December 31, 2018	$ 227

The Company's policy is to recognize interest and penalties related to uncertain tax positions as income tax benefit (expense) in the Company's Consolidated Statements of Operations. The Company had no interest or penalties related to unrecognized tax benefits for the year ended December 31, 2018 or any prior years. The total amount of unrecognized tax benefit, if recognized, that would affect the effective tax rate was zero.

The Company's tax returns are subject to periodic audits by the various jurisdictions in which the Company operates. These audits can result in adjustments of taxes due or adjustments of the NOL carryforwards that are available to offset future taxable income. The Company does not anticipate that the total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2018.

Generally, the Company's income tax years of 1999 through 2017 remain open and subject to examination by Federal tax authorities, and the tax years of 2011 through 2017 remain open and subject to examination by the tax authorities in Texas and Louisiana which are the jurisdictions where the Company carries its principal operations.

16. Subsequent Events

The Company has evaluated subsequent events through the date the financial statements were available to be issued. Nothing that would require recognition or disclosure in the financial statements was identified in addition to the items disclosed in the financial statements.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited)

In accordance with U.S. GAAP for disclosures regarding oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures regarding our natural gas and oil reserves and exploration and production activities.

Capitalized Costs Related to Oil and Gas Producing Activities

The following table presents information regarding our net capitalized costs related to oil and gas producing activities as of the date indicated (in thousands):

	December 31,	
	2018	2017
Proved oil and gas properties	$ 1,095,417	$ 1,239,662
Unproved oil and gas properties	34,612	35,243
	1,130,029	1,274,905
Less accumulated depreciation, depletion, amortization and impairment	(897,140)	(929,210)
Net capitalized costs	$ 232,889	$ 345,695

Costs Incurred

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

	Year Ended December 31,	
	2018	2017
Property acquisition costs:		
Unproved	$ 10,339	$ 6,540
Proved	—	—
Exploration costs	1,637	8,158
Development costs	42,516	45,016
Total costs incurred	$ 54,492	$ 59,714

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

	Year Ended December 31,	
	2018	2017

Property acquisition costs	$ —	$ —
Exploration costs	—	—
Development costs	169	429
Total costs incurred	$ 169	$ 429

Natural Gas and Oil Reserves

Proved reserves are the estimated quantities of natural gas, oil and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and current regulatory practices. Proved developed reserves are proved reserves which are expected to be produced from existing completion intervals with existing equipment and operating methods.

Proved natural gas and oil reserve quantities at December 31, 2018, 2017 and 2016, and the related discounted future net cash flows before income taxes are based on estimates prepared by William M. Cobb & Associates, Inc. and Netherland, Sewell & Associates, Inc. All estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

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The below table summarizes the Company’s net ownership interests in estimated quantities of proved natural gas, oil and natural gas liquids (“NGLs”) reserves and changes in net proved reserves as of December 31, 2018, 2017 and 2016, all of which are located in the continental United States.

	Oil and Condensate (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Proved Developed and Undeveloped Reserves as of:				
December 31, 2016	3,424	4,359	105,053	151,750
Sale of minerals in place	—	—	(893)	(893)
Extensions and discoveries	7,159	1,989	8,191	63,076
Revisions of previous estimates	584	(224)	(6,722)	(4,556)
Production	(518)	(517)	(13,910)	(20,123)
December 31, 2017	10,649	5,607	91,719	189,254
Sale of minerals in place	(1,914)	(519)	(10,636)	(25,234)
Extensions and discoveries	3,977	795	4,499	33,136
Revisions of previous estimates	(2,708)	(1,893)	(21,597)	(49,206)
Production	(570)	(473)	(9,779)	(16,039)
December 31, 2018	9,434	3,517	54,206	131,911
Proved Developed Reserves as of:				
December 31, 2016	2,158	3,509	95,396	129,399
December 31, 2017	3,364	3,596	82,133	123,895
December 31, 2018	3,103	2,297	46,840	79,234
Proved Undeveloped Reserves as of:				
December 31, 2016	1,266	850	9,657	22,351
December 31, 2017	7,285	2,011	9,586	65,359
December 31, 2018	6,331	1,220	7,366	52,677

During the year ended December 31, 2018, our proved reserves declined by approximately 57.3 Bcfe primarily due to property sales throughout the year, a negative revision related to our West Texas type curve resulting from analysis of longer term decline experience and a decrease in our GOM developed reserves related to negative revisions announced in the third quarter. Partially offsetting these reserve decreases were new additions and extensions related to our drilling program.

During the year ended December 31, 2017, our proved reserves increased by approximately 37.5 Bcfe attributable primarily to new additions and extensions related to our drilling program in West Texas and positive revisions of reserve estimates due to higher commodity prices, partially offset by 2017 production and a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded.

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The below table summarizes the Company’s net ownership interests in estimated quantities of proved natural gas and oil reserves and changes in net proved reserves as of December 31, 2018, 2017 and 2016, attributable to its Investment in Exaro.

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Proved Developed and Undeveloped Reserves as of:			
December 31, 2016	360	30,441	32,600
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Revisions of previous estimates	6	1,635	1,672
Production	(37)	(3,330)	(3,553)
December 31, 2017	329	28,746	30,719
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Revisions of previous estimates	(28)	(1,043)	(1,212)
Production	(29)	(2,738)	(2,912)
December 31, 2018	272	24,965	26,595
Proved Developed Reserves as of:			
December 31, 2016	360	30,441	32,600
December 31, 2017	325	28,443	30,390
December 31, 2018	272	24,965	26,595
Proved Undeveloped Reserves as of:			
December 31, 2016	—	—	—
December 31, 2017	4	303	329
December 31, 2018	—	—	—

During the year ended December 31, 2018, the decrease in Exaro’s proved reserves attributable to our Investment in Exaro was approximately 4.1 Bcfe.

During the year ended December 31, 2017, the decrease in Exaro’s proved reserves attributable to our Investment in Exaro was approximately 1.9 Bcfe.

Standardized Measure

The standardized measure of discounted future net cash flows relating to the Company’s ownership interests in proved natural gas and oil reserves as of December 31, 2018 and 2017 are shown below (in thousands):

	As of December 31,	
	2018	2017

Future cash inflows	$ 854,869	$ 877,721
Future production costs	(271,679)	(243,415)
Future development costs	(165,919)	(138,840)
Future income tax expenses	(3,407)	(3,226)
Future net cash flows	413,864	492,240
10% annual discount for estimated timing of cash flows	(194,920)	(236,333)
Standardized measure of discounted future net cash flows	$ 218,944	$ 255,907

Future cash inflows represent expected revenues from production and are computed by applying certain prices of natural gas and oil to estimated quantities of proved natural gas and oil reserves. Prices are based on the first-day-of-the-month prices for the previous 12 months. As of December 31, 2018, future cash inflows were based on unadjusted prices of $3.10 per MMbtu of natural gas, $64.80 per barrel of oil, and $27.89 per barrel of NGLs. As of December 31, 2017, future cash inflows were based on unadjusted prices of $2.98 per MMbtu of natural gas, $49.92 per barrel of oil, and $18.59 per barrel of NGLs.

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The standardized measure of discounted future net cash flows relating to the Company’s ownership interests in proved natural gas and oil reserves as of December 31, 2018 and 2017 attributable to its Investment in Exaro are shown below (in thousands):

	As of December 31,	
	2018	2017
Future cash inflows	$ 91,792	$ 102,813
Future production costs	(55,448)	(60,541)
Future development costs	(2,268)	(2,699)
Future income tax expenses (1)	—	—
Future net cash flows	34,076	39,573
10% annual discount for estimated timing of cash flows	(13,075)	(15,207)
Standardized measure of discounted future net cash flows	$ 21,001	$ 24,366

(1) Exaro does not include the effect of income taxes because Exaro is treated as a partnership for tax purposes.

Realized Prices

The average realized prices for the year ended December 31, 2018 production were $3.05 per MCF of gas, $60.43 per barrel of oil, and $27.04 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging losses of $3.5 million for the year ended December 31, 2018.

The average realized prices for the year ended December 31, 2017 production were $2.97 per MCF of gas, $48.90 per barrel of oil, and $22.97 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging gains of $1.1 million for the year ended December 31, 2017.

Future production and development costs are estimated expenditures to be incurred in developing and producing the Company’s proved natural gas and oil reserves based on historical costs and assuming continuation of existing economic conditions. Future development costs relate to compression charges at our platforms, abandonment costs, recompletion costs and additional development costs for new facilities.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company’s natural gas and oil properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates of natural gas and oil producing operations.

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Change in Standardized Measure

Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves are summarized below (in thousands):

	Year Ended December 31,	
	2018	2017
Changes in standardized measure due to current year operation:		
Sales of natural gas and oil produced during the period, net of production expenses	$ (51,496)	$ (51,359)
Extensions and discoveries	46,732	69,179
Net change in prices and production costs	33,195	57,026
Changes in estimated future development costs	(2,096)	—
Revisions in quantity estimates	(58,063)	4,546
Purchase of reserves	—	—
Sale of reserves	(38,257)	(235)
Previously estimated development costs incurred	4,467	—
Accretion of discount	25,728	16,623
Changes in income taxes	(188)	(1,376)
Change in the timing of production rates and other	3,015	(4,725)
Net change	(36,963)	89,679
Beginning of year	255,907	166,228
End of year	$ 218,944	$ 255,907

During the year ended December 31, 2018, our proved reserves decreased by approximately 57.3 Bcfe, and our standardized measure decreased by approximately $37.0 million. This decrease is primarily attributable to non-core property sales throughout the year and negative revisions of reserve estimates due to a revision of our West Texas type curve as discussed above and the previously disclosed revision to the Eugene Island field as a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression.

During the year ended December 31, 2017, our proved reserves increased by approximately 37.5 Bcfe, and our standardized measure increased by approximately $89.7 million. This increase is primarily attributable to the extensions and additions related to our assets in West Texas and positive revisions of reserve estimates due to higher commodity prices, partially offset by decreases attributable to production and decreases due to the expiration of undeveloped reserves.

Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves attributable to the Company’s investment in Exaro are summarized below (in thousands):

	Year Ended December 31,	
	2018	2017
Changes in standardized measure due to current year operation:		
Sales of natural gas and oil produced during the period, net of production expenses	$ (5,056)	$ (6,744)
Extensions and discoveries	—	—
Net change in prices and production costs	1,024	9,951
Changes in estimated future development costs	7	5
Revisions in quantity estimates	(808)	1,236
Purchase of reserves	—	—

Sale of reserves	—	—
Previously estimated development costs incurred	99	—
Accretion of discount	2,437	1,978
Changes in income taxes	—	—
Change in the timing of production rates and other	(1,068)	(1,838)
Net change	(3,365)	4,588
Beginning of year	24,366	19,778
End of year	$ 21,001	$ 24,366

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations

The following table sets forth the results of operations by quarter for the fiscal years ended December 31, 2018 and 2017, (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
Year ended December 31, 2018:				
Revenues	$ 20,437	$ 18,448	$ 19,508	$ 18,694
Operating Loss (1)	$ (7,497)	$ (4,053)	$ (79,400)	$ (28,698)
Net income (loss) attributable to common stock (2)	$ 937	$ (7,178)	$ (81,524)	$ (33,803)
Net income (loss) per share (3):				
Basic:	$ 0.04	$ (0.29)	$ (3.26)	$ (1.16)
Diluted:	$ 0.04	$ (0.29)	$ (3.26)	$ (1.16)
Year ended December 31, 2017:				
Revenues	$ 19,424	$ 20,276	$ 18,830	$ 20,015
Operating Loss (1)	$ (5,897)	$ (6,285)	$ (6,022)	$ (5,311)
Net income (loss) attributable to common stock (2)	885	(6,034)	(6,916)	(5,578)
Net income (loss) per share (3):				
Basic:	$ 0.04	$ (0.24)	$ (0.28)	$ (0.23)
Diluted:	$ 0.04	$ (0.24)	$ (0.28)	$ (0.23)

(1) Represents natural gas and oil sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of natural gas and oil properties and general and administrative expense.
(2) Represents natural gas and oil sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of natural gas and oil properties, general and administrative expense, and other income and expense after income taxes.
(3) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share as each quarterly computation is based on the income for that quarter and the weighted average number of common shares outstanding during that quarter.