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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 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 expressions identify forward-looking statements and express our expectations about future events. Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties that could cause or contribute to such differences include, without limitation, those discussed in the section entitled "Risk Factors" included in this report and those factors summarized below:

- our ability to continue as a going concern;
- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin and realize the benefits associated therewith;
- our financial position;
- our business strategy, including execution of any changes in our strategy;
- meeting our forecasts and budgets, including our 2019 capital expenditure budget;
- expectations regarding natural gas and oil markets in the United States;
- volatility in natural gas, natural gas liquids and oil prices, including regional differentials;
- operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and natural gas processing facilities;
- the risks associated with acting as operator of deep high pressure and high temperature wells, including well blowouts and explosions;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which we have made a large capital commitment relative to the size of our capitalization structure;
- the timing and successful drilling and completion of natural gas and oil wells;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and fund our drilling program;
- our ability to comply with financial covenants in our debt instruments, repay indebtedness and access new sources of indebtedness;
- the cost and availability of rigs and other materials, services and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;
- our ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- our ability to complete strategic dispositions or acquisitions of assets or businesses and realize the benefits of such dispositions or acquisitions;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;

- the need to take impairments on our properties due to lower commodity prices;
- the ability to post additional collateral for current bonds or comply with new supplemental bonding requirements imposed by the Bureau of Ocean Energy Management;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures and other risks;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;
- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to retain key members of senior management and key technical employees and to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals (including additional taxes and changes in environmental regulations);
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements;
- the ability to obtain adequate insurance coverage on commercially reasonable terms; and
- the limited trading volume of our common stock and general market volatility.

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

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

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

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.

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.

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

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.

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.

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.

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,

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.

- 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.

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

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

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

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

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to potentially assess maximum civil penalties of approximately $1.18 million per day per violation, subject to annual adjustment for inflation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

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

There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. We do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of petroleum with which we compete.

Environmental and Occupational Health and Safety Matters

Our crude oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment, or otherwise relating to environmental protection. Numerous governmental authorities, including the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause us to incur significant capital expenditures or costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays, cancellations or restrictions in permitting or performance of projects and the issuance of orders enjoining some or all of our operations in affected areas. The public continues to have a significant interest in the protection of the environment. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment, and thus any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly exploration, production and development activities, or waste handling, storage transport, disposal or remediation requirements could result in increased costs of our doing business and consequently affect our profitability. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund Law", and similar state laws, impose strict joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the current or past owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property or natural resource damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

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

The federal Clean Air Act, as amended (the "CAA"), and comparable state laws restrict the emission of air pollutants from many sources and also impose various pre-construction, operating, monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of crude oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues.

There remains continued public, governmental and scientific attention regarding climate change, with the EPA having determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment. As a result, the EPA has adopted regulations under existing provisions of the CAA that, among other things, impose permit reviews and restrict emissions of GHGs from certain large stationary sources. These EPA regulations could adversely affect our operations and restrict, delay or halt our

ability to obtain air permits for new or modified sources. Additionally, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including certain onshore and offshore production facilities, which include the majority of our operations. We are monitoring and annually reporting on GHG emissions from certain of our operations.

While Congress has, from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that include consideration of cap-and-trade programs whereby major sources of GHG emissions are required to acquire and surrender emission allowances in return for emitting those GHGs, as well as carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Internationally, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by the United States in April 2016, requires countries to review and "represent a progression" in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. In June 2017, the Trump administration announced its intention for the United States to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the earliest date the United States can withdraw is November 2020. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future international, federal or state laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

The Federal Water Pollution Control Act, as amended (the "Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. Any such discharge of pollutants into regulated waters is prohibited except in accordance with the terms of an issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. The EPA and the U.S. Army Corps of Engineers released a rule to revise the definition of "waters of the United States," or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. The EPA has instituted rulemakings to both delay the effective date of this rule and repeal the rule. Federal district court decisions have preserved the stay in a majority of states, which remain subject to pre-2015 regulated waters regulations, whereas the stay has been enjoined in a minority of states. Litigation surrounding this rule is ongoing. More recently, on December 11, 2018, the EPA and the Corps released a proposal to revise the 2015 Clean Water Rule so as to narrow the regulatory definition of waters of the United States; the revised rule has not yet been finalized.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended (the "SDWA"), and analogous state laws. Our oil and natural gas exploration and production operations generate produced water, drilling muds and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations, and thus, those activities are subject to the SWDA. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities that may be injected, and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for alternative water supplies, property and natural resource damages and personal injuries. Furthermore, in response to a growing concern that the injection of produced water and other fluids into belowground disposal wells triggers seismic activity in certain areas, some states, including Texas, where we operate, have imposed, and other states are considering imposing, additional requirements in the permitting or operation of produced water injection wells. In Texas, the Texas Railroad Commission ("TRC") has adopted a final rule governing the permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well fails to demonstrate that

the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and natural gas activities utilizing injection wells for produced water disposal. These existing and any new seismic requirements applicable to disposal wells that impose more stringent permitting or operational requirements could result in added costs to comply or, perhaps, may require alternative methods of disposing of produced water and other fluids, which could delay production schedules and also result in increased costs.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations. We routinely use hydraulic fracturing techniques in many of our completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or other similar state agencies, but several federal agencies have also asserted regulatory authority over, or conducted investigations that focus upon, certain aspects of the process, including a suite of proposed rulemakings and final rules issued by the EPA and the federal Bureau of Land Management (the "BLM"), which legal requirements, to the extent finalized and implemented by the agencies, may impose more stringent requirements relating to the composition of fracturing fluids, emissions and discharges from hydraulic fracturing, chemical disclosures, and performances of fracturing activities on federal and Indian lands. Congress has from time to time considered, but not enacted, legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process while, at the state level, several states, including Texas and Wyoming, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

The National Environmental Policy Act, as amended ("NEPA") is applicable to oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM. NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Governmental permits or authorizations that are subject to the requirements of NEPA are required for exploration and development projects on federal and Indian lands. This process has the potential to delay, limit or

increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

The federal Endangered Species Act, as amended ("ESA"), provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits taking of endangered species. The ESA may impact exploration, development and production activities on public or private lands. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act, as amended. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of one or more settlements entered into by the U.S. Fish and Wildlife Service (the "FWS"), the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA by specified timelines. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures as well as time delays or limitations on or cancellations of our drilling program activities, which costs, delays, limitations or cancellations could have an adverse impact on our ability to develop and produce reserves.

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the U.S. Occupational Safety and Health Administration hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

The BOEM and the BSEE, each agencies of the U.S. Department of the Interior, have, over time, imposed more stringent permitting procedures and regulatory safety and performance requirements for wells in federal waters. For example, in 2016, the BOEM issued a Notice to Lessees and Operators (the "NTL #2016-N01") that became effective in September 2016 and bolsters supplemental financial assurance requirements for the decommissioning of offshore wells, platforms, pipelines and other facilities whereas the BSEE has issued various regulations relating to the safe and environmentally responsible development of energy and mineral resources on the OCS that have resulted in more stringent requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. Additionally, states may adopt and implement similar or more stringent legal requirements applicable to exploration and production activities in state waters. Compliance with these more stringent regulatory restrictions, together with any uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect, delay or cancel new drilling and ongoing development efforts. If the BOEM determines that increased financial assurance is required in connection with our offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled. Also, if material spill incidents were to occur, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which developments could have a material adverse effect on our business. Any of the offshore-related matters described above could have a material adverse effect on our business, financial condition and results of operations.

These regulatory actions, or any new rules, regulations or legal initiatives that may be adopted or enforced by the BOEM or the BSEE in the future could delay or disrupt our oil and natural gas exploration and production operations conducted offshore, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit or cancel activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases.

Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee, or any subsequent assignee, is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees, or any subsequent assignee, of offshore facilities is unwilling or unable to perform, we could incur costs to perform decommissioning, which costs could be material. If the BOEM determines that increased financial assurance is required in connection with our or any previously

assigned offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled.

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

Other Laws and Regulations

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

Whereas the BLM administers oil and natural gas leases held by the Company on federal onshore lands, the BOEM administers the natural gas and oil leases held by the Company on federal offshore tracts on the OCS. The Office of Natural Resources Revenue (the "ONRR") collects a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the ONRR changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells, decommission or remove platforms and pipelines, and clear the seafloor of obstructions at the end of production (collectively, "decommissioning obligations"), the BOEM generally requires that lessees post supplemental bonds or other acceptable financial assurances that such obligations will be met. Historically, our financial assurance costs to satisfy decommissioning obligations have not had a material adverse effect on our results of operations; however, the BOEM continues to consider imposing more stringent financial assurance requirements on offshore operators on the OCS. For example, the BOEM issued NTL #2016-N01 that went into effect in September 2016 and augments requirements for the posting of additional financial assurance by offshore lessees, among others, to assure that sufficient funds are available to satisfy decommissioning obligations on the OCS. If the BOEM determines under this new NTL that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. In June 2017, the BOEM extended indefinitely the start date for implementation of NTL #2016-N01. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning obligations.

The BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the BOEM determines whether and to what extent any additional financial assurance may be required by us with respect to our offshore operations, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties. In the event that we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require certain of our operations on federal leases to be suspended or cancelled or otherwise impose monetary penalties. See "Item 1A. Risk Factors" for a further discussion on BOEM and its implementation of NTL #2016-N01.

Risk and Insurance Program

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such

occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice, and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

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

Health, Safety and Environmental Program

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

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

We also have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs in the event of a spill. CGA specializes in onsite control and cleanup and is on 24-hour alert with equipment currently stored at eight bases along the gulf coast, from South Texas to East Louisiana. The CGA equipment stockpile is available to serve member oil spill response needs and includes open seas skimmers, shoreline protection boom, communications equipment, dispersants with application systems, wildlife rehabilitation and a forward command center. CGA has retainers with aerial dispersant and mechanical recovery equipment contractors for spill response.

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

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

Safety and Environmental Management System

We have developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the OCS, as required by the BSEE. Our SEMS identifies and mitigates safety and environmental hazards and the impacts of these hazards on design, construction, start-up, operation, inspection and maintenance of all new and existing facilities. The Company has established goals, performance measures, training and accountability for SEMS implementation. We also provide the necessary resources to maintain an effective SEMS, and we review the adequacy and effectiveness of the SEMS program annually. Company facilities are designed, constructed, maintained, monitored and operated in a manner compatible with industry codes, consensus standards and all applicable governmental regulations. We have contracted with Island Technologies Inc. to coordinate our SEMS program and to track compliance for production operations.

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

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

and prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. Lower prices also affect the amount of natural gas, NGLs and oil that we can economically produce. Factors that can cause price fluctuations include:

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

A substantial or extended decline in natural gas, NGL and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas, NGLs and oil that may be economically produced by us. The Company may utilize financial derivative contracts, such as swaps, costless collars and puts on commodity prices, to reduce exposure to potential declines in commodity prices. However, these derivative contracts may not be sufficient to mitigate the effect of lower commodity prices.

Part of our strategy involves drilling in new or emerging plays, and a reduction in our drilling program may affect our revenues and access to capital.

The results of our drilling in new or emerging plays are more uncertain than drilling results in areas that are more developed and with longer production history. Since new or emerging plays and new formations have limited production history, we are less able to use past drilling results in those areas to help predict our future drilling results. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or crude oil, natural gas and NGL price declines. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

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

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

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

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

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

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

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

Our bank borrowing base is adjusted semiannually in May and November of each year, and upon requested unscheduled special redeterminations, in each case at the banks' discretion, and the amount is established and based, in part, upon certain external factors, such as commodity prices. Under the Sixth Amendment, effective November 2, 2018, the borrowing base of $105 million was reaffirmed but the borrowing base was reduced to $90 million at January 31, 2019. This lowering of our borrowing base limits availability under our bank Credit Facility or requires us to seek

different forms of financing arrangements, and we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding upon its maturity. If the outstanding debt under our Credit Facility were to ever exceed the borrowing base, we would be required to repay the excess amount within a short period. Such acceleration of indebtedness could require us to pursue strategic restructuring options, which would have a material adverse effect on the trading price of our common stock.

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

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of crude oil, natural gas and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations, borrowings under our Credit Facility and/or proceeds from non-core asset sales and our 2018 underwritten public offering of common stock. Our cash flow from operations and access to capital is subject to a number of variables, including:

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

If our revenues decrease as a result of lower crude oil, natural gas and natural gas liquids prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our Credit Facility contains covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base redetermination results in a lower borrowing base under our Credit Facility, we may be unable to obtain financing otherwise currently available under our Credit Facility. As part of the regular redetermination schedule, the borrowing base on our Credit Facility was redetermined at $105 million effective November 2, 2018 and through January 31, 2019, decreasing automatically to $90 million on that date and until the next regular redetermination date of May 01, 2019. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity.”

In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness is uncertain and will be affected by our future performance and events or circumstances beyond our control. Any future failure to comply with these covenants could result in an event of default under such indebtedness and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under any of our other outstanding indebtedness.

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

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.

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

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;

- 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.

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

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

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

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. For example, our total production for the year ended December 31, 2017 declined by 0.4 Mmcfe/d as a result of downtime associated with the impact of Hurricane Harvey. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

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

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

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices 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.

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

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.

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.

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.

- *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

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

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

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

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

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand or other proppant and chemical additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or similar state agencies, but several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process. For example, the EPA has asserted regulatory authority pursuant to the SDWA Underground Injection Control program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities, as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The EPA also published final rules under the CAA in 2012 and in 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Additionally, in 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The BLM also published a final rule in 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in federal district court. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic

fracturing may impact drinking water resources under certain circumstances, including as a result of water withdrawals for fracturing in times or areas of low water availability or due to surface spills during the management of fracturing fluids, chemicals or produced water.

Moreover, from time to time, Congress has considered, but not enacted, legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, certain states, including Texas and Wyoming, where we conduct operations, have adopted and other states are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. Additionally, non-governmental organizations may seek to restrict hydraulic fracturing, as has been the case in Colorado in recent years, when certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or costly in the future including, for example, by increasing mandatory setback distances of oil and natural gas operations, including hydraulic fracturing, from specific occupied structures and/or certain environmentally sensitive or recreational areas. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

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

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

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

If we fail to comply with any orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if

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.

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;

- 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.

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.

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

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

	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

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

	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.

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.

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.

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

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

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.

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.

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.

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.

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**
Offshore GOM								
Dutch and Mary Rose [1]	35.4	36.3	32.2	30.8	29.0	21.0	25.2	24.2
Vermilion 170 [2]	4.6	3.1	4.2	3.5	3.0	2.7	2.0	1.1
South Timbalier 17 [3]	0.5	0.2	0.1	—	—	—	—	—
Southeast Texas [4]	8.6	8.2	7.8	7.5	7.3	6.4	6.0	3.9
South Texas [5]	6.4	5.6	4.6	5.8	5.3	4.5	3.1	2.4
West Texas	0.6	3.3	3.2	3.2	4.5	6.7	6.4	7.5
Other [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.

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)%

	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%

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.

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.

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.

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

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

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.

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.

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 operation**s.**

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

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.

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

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	—

(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.

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.

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

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.

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).

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).

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).

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. †

* Indicates a management contract or compensatory plan or arrangement

† Filed herewith

† † Furnished herewith

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
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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, 2017	1,573	1,223
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.

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.

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.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(in thousands, expect share amounts)

	Common Stock		Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
	Shares	Amount				
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.

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

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.

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.

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.

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.

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

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.

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.

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.

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.

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

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

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

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

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.

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

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

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.

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.

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)

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.

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.

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.

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.

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.

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

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.

CERTIFICATE OF ELIMINATION
OF
SERIES A JUNIOR PARTICIPATING PREFERRED STOCK
OF CONTANGO OIL & GAS COMPANY

(Pursuant to Section 151 of the Delaware General Corporation Law)

Contango Oil & Gas Company, a Delaware corporation (the "**Company**"), certifies as follows:

1. Pursuant to Section 151 of the Delaware General Corporation Law (the "**DGCL**") and the authority granted in the Company's Certificate of Incorporation, as amended, and as may be further amended from time to time (the "**Certificate of Incorporation**"), the Board of Directors of the Company, by resolutions duly adopted on July 31, 2018, authorized the issuance of 27,000 shares of preferred stock, par value $0.04 per share, of the Company designated as Series A Junior Participating Preferred Stock (the "**Series A Preferred Stock**").

2. Pursuant to the provisions of Section 151(g) of the DGCL, the Board of Directors of the Company adopted the following resolutions:

FURTHER RESOLVED, that none of the authorized shares of Series A Preferred Stock are outstanding, and none of the authorized shares of the Series A Preferred Stock will be issued pursuant to the Certificate of Designations of Series A Preferred Stock filed with the Secretary of State of the State of Delaware on August 1, 2018 (the "**Certificate of Designations**");

FURTHER RESOLVED, that the Company be, and hereby is, authorized and directed to file with the Secretary of State of the State of Delaware a certificate of elimination (the "**Certificate of Elimination**") setting forth a copy of these resolutions, with the effect under the DGCL of eliminating from the Certificate of Incorporation all matters set forth in the Certificate of Designations, and the shares of Series A Preferred Stock that were designated to such series shall be returned to the status of authorized but unissued shares of preferred stock of the Company without designation as to series; and

FURTHER RESOLVED, that E. Joseph Grady, the Company's Senior Vice President and Chief Financial Officer, and any other officer of the Company designated by him, are, and each of them individually hereby is, authorized and directed, for and on behalf of the Company and in its name, to execute and file the Certificate of Elimination at such time as they deem appropriate, and to take such further actions as they may deem necessary or appropriate to carry out the intent of the foregoing resolutions in accordance with the applicable provisions of the DGCL.

3. Pursuant to the provisions of Section 151(g) of the DGCL, all references to the Series A Preferred Stock in the Certificate of Incorporation are hereby eliminated, and the shares that were designated to such series are hereby returned to the status of authorized but unissued shares of preferred stock of the Company, without designation as to series.

IN WITNESS WHEREOF, the Company has caused this Certificate of Elimination to be signed on its behalf by its duly authorized officer on this 14th day of March, 2019.

CONTANGO OIL & GAS COMPANY

/s/ E. JOSEPH GRADY
Name: E. Joseph Grady
Title: Senior Vice President and Chief Financial Officer

Exhibit 10.4
Execution Copy

SECOND AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT

OF

EXARO ENERGY III LLC

(A DELAWARE LIMITED LIABILITY COMPANY)

DATED EFFECTIVE AS OF FEBRUARY 1, 2013

THE MEMBERSHIP INTERESTS REPRESENTED BY THIS AGREEMENT HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED, OR UNDER ANY STATE SECURITIES ACTS OR OTHER SIMILAR STATUTES IN RELIANCE UPON EXEMPTIONS UNDER THOSE ACTS. THE SALE OR OTHER DISPOSITION OF THE MEMBERSHIP INTERESTS IS PROHIBITED UNLESS SUCH SALE OR DISPOSITION IS MADE IN COMPLIANCE WITH ALL SUCH APPLICABLE ACTS, OR UNLESS AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT AND UNDER ANY APPLICABLE STATE SECURITIES LAWS IS AVAILABLE IN CONNECTION WITH SUCH TRANSFER. ADDITIONAL RESTRICTIONS ON THE TRANSFER OF THE MEMBERSHIP INTERESTS ARE SET FORTH IN THIS AGREEMENT. BY ACQUIRING THE MEMBERSHIP INTERESTS IN THE COMPANY, EACH MEMBER REPRESENTS THAT IT HAS ACQUIRED THE MEMBERSHIP INTERESTS FOR INVESTMENT AND THAT IT WILL NOT SELL OR OTHERWISE DISPOSE OF THE MEMBERSHIP INTERESTS WITHOUT REGISTRATION OR OTHER COMPLIANCE WITH THE AFORESAID ACTS AND THE RULES AND REGULATIONS THEREUNDER, UNLESS AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT AND UNDER ANY APPLICABLE STATE SECURITIES LAWS IS AVAILABLE IN CONNECTION WITH THE TRANSFER.

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Exhibit 10.4

SECOND AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT
OF
EXARO ENERGY III LLC

THIS SECOND AMENDED AND RESTATED LIMITED LIABILITY COMPANY AGREEMENT (this "*Agreement*") of Exaro Energy III LLC, a Delaware limited liability company (the "*Company*"), dated effective as of February 1, 2013 (the "*Second Amendment Date*"), is made by the Company and those Persons who become signatories hereto or otherwise bound hereby;

WHEREAS, the Certificate of Formation (the "*Certificate*") of the Company was filed with the Delaware Secretary of State on March 19, 2012;

WHEREAS, the Company currently is governed by the First Amended and Restated Limited Liability Company Agreement of the Company dated as of March 31, 2012 (the "*First Amended and Restated Agreement*");

WHEREAS, the Members desire to amend and restate the First Amended and Restated Agreement; and

NOW, THEREFORE, the First Amended and Restated Agreement is hereby amended and restated to read in its entirety as follows:

ARTICLE 1
ORGANIZATION

1.1 Formation.

The Company has been organized as a Delaware limited liability company pursuant to the Act. The Members hereby agree that during the term of the Company, the rights and obligations of the Members with respect to the Company will be determined in accordance with the terms and provisions of this Agreement and, except where the Act provides that such rights and obligations specified in the Act shall apply "unless otherwise provided in a limited liability company agreement" or words of similar effect and such rights and obligations are set forth in this Agreement, the Act. Notwithstanding anything herein to the contrary, Section 18-210 of the Act (entitled "Contractual Appraisal Rights") shall not apply or be incorporated into this Agreement.

1.2 Name.

The name of the Company is "*Exaro Energy III LLC*." Subject to all applicable laws, all business of the Company shall be conducted in such name or under such other name or names as the Board of Managers shall determine from time to time. Management shall cause to be filed on behalf of the Company such assumed or fictitious name certificates or similar instruments as may from time to time be required by law.

1.3 Business.

The business of the Company shall be (a) to enter into, execute and perform under the Earning and Development Agreement (the "*Development Agreement*") between the Company and Encana Oil & Gas (USA) Inc. ("*Encana*") dated as of April 1, 2012, relating to a development drilling program within a defined area of Encana's Jonah Field asset located in Sublette County, Wyoming, (b) pursue oil and gas opportunities other than as provided for in the Development Agreement that are approved by the Board of Managers and by Supermajority Member Approval and (c) to take all such other actions incidental or ancillary to the foregoing as the Board of Managers may determine to be necessary or desirable.

1.4 Places of Business; Registered Agent.

(a) The address of the principal office and place of business of the Company shall be 1800 Bering Drive, Suite 540, Houston, Texas 77057. The Board of Managers may change the location of the Company's principal place of business and may establish such additional place or places of business of the Company as the Board of Managers may designate from time to time.

(b) The registered office of the Company required by the Act to be maintained in the State of Delaware shall be the initial registered office named in the Certificate or such other office (which need not be a place of business of the Company) as the Board of Managers may designate from time to time in the manner provided by law. The registered agent of the Company in the State of Delaware shall be the initial registered agent named in the Certificate or such other Person as the Board of Managers may designate from time to time in the manner provided by law. The Board of Managers may designate additional offices and/or agents and may change any registered office or agent of the Company at any time as deemed advisable.

1.5 Term.

Pursuant to the Act, the existence of the Company began on the date of the filing of the Certificate with the Secretary of State of Delaware and shall continue until the Company is dissolved, liquidated and terminated as provided in Article 8.

1.6 Qualification in Other Jurisdictions.

The Board of Managers shall have authority to cause the Company to do business in any jurisdiction only if such jurisdiction recognizes the limited liability of the Members to substantially the same extent as would be recognized for a limited liability company under the laws of the State of Delaware. The Board of Managers shall cause the Company to be qualified, formed, reformed or registered under assumed or fictitious name statutes or similar laws in any jurisdiction in which the Company transacts business if such qualification, formation, reformation or registration is necessary or desirable in order to protect the limited liability of the Members or to permit the Company lawfully to transact business; provided, the Company shall not transact business in any such jurisdiction where any of the required actions described in this sentence would materially change the rights, liabilities, duties and obligations of the Members under this Agreement.

1.7 No State Law Partnership.

No provision of this Agreement shall be interpreted so as to deem or construe the Company as a partnership (including a limited partnership) or joint venture or any Member or Manager as a partner or joint venturer of any other Member or Manager for any purposes other than federal and state tax purposes.

1.8 Title to Company Property.

All property contributed to the Company or acquired by the Company, whether real or personal, tangible or intangible, shall be deemed to be owned by the Company as an entity, and no Member, individually, shall have any ownership interest in such property in his or its separate name or right. The Company may hold its property in its own name or in the name of a nominee determined by the Board of Managers.

1.9 Alternative Investment Structures.

If the Board of Managers determines that for legal, tax, regulatory or other similar reasons it is in the best interests of some or all of the Members that an investment by the Company be made through an alternative investment structure (including, through a non-United States limited partnership, a non-United States limited liability company, or other similar vehicle, formed for the purpose of making investments outside the United States) (an "*Alternative Investment Vehicle*"), the Board of Managers may cause the Company to structure the making of all or any portion of such investment outside of the Company (or restructure any such investment or Alternative Investment Vehicle), by requiring any Member or Members to make such investment directly or indirectly through separate limited partnerships, limited liability companies (or other vehicles) that will invest on a parallel basis with or in lieu of the Company, as the case may be; provided, however, that such Member, if such Member is a Potentially Restricted Member, shall not be obligated to make an investment in such Alternative Investment Vehicle if such Potentially Restricted Member, in its reasonable and good faith judgment, determines (in such case such Potentially Restricted Member shall submit an opinion of its internal counsel if requested by the Company as to such determination) that one or more laws, rules, regulations or government orders prohibits or restrains such Potentially Restricted Member from investing in such Alternate Investment Vehicle, and such Potentially Restricted Member shall not be considered a Defaulting Member under this Agreement with respect to such determination (any Potentially Restricted Member that determines not to invest in any Alternative Investment Vehicle in accordance with the foregoing is referred to herein with respect to such Alternative Investment Vehicle as an "*Opt-Out Member*"). To the extent required by the Board of Managers, each such vehicle will enter into agreements with the Company and other appropriate parties to allocate any applicable fees or other items of income or expense, or any capital contributions, among the Company, such vehicle, and any other Alternative Investment Vehicles; provided that all of the incremental organizational costs of any such Alternative Investment Vehicle will be allocated 100% to such vehicle. The Members (other than any Opt-Out Member) will be required to make Capital Contributions directly to each such Alternative Investment Vehicle to the same extent, for the same purposes and on the same terms and conditions and subject to the same conditions and approvals as Members are required to make Capital Contributions to the Company. Each Member (other than any Opt-Out Member) will have the same economic interest in all material respects with respect to investments described in this Section 1.9 as such Member would have if such investment had been made by the Company, and the other terms of such

Alternative Investment Vehicle will be substantially identical in all material respects to those of the Company, to the maximum extent applicable (including, but not limited to, rights substantially identical to Section 3.7 and Section 9.3(b)); provided that (a) such Alternative Investment Vehicle (or the Entity in which such Alternative Investment Vehicle invests) will provide for the limited liability of the Members as a matter of the organizational documents of such Alternative Investment Vehicle (or the Entity in which such Alternative Investment Vehicle invests) and as a matter of local law to the same extent in all material respects as is provided to the Members under the Act and this Agreement, (b) the Board of Managers will serve as the Board of Managers or comparable body of such Alternative Investment Vehicle, (c) distributions of cash and other property and the allocations of income, gain, loss, deduction, expense and credit from such Alternative Investment Vehicle, and the determination of allocations and distributions pursuant to this Agreement, will be determined as if each investment made by such Alternative Investment Vehicle were an investment made by the Company (subject in each case to adjustment or necessary to give effect to any Opt-Out Member's election not to make Capital Contributions to such Alternative Investment Vehicle), (d) any Alternative Investment Vehicle will, subject to applicable legal, tax and regulatory considerations, terminate upon the termination of the Company and (e) if deemed appropriate for the Company by the Board of Managers, the relationships between the Company and any Alternative Investment Vehicle (and among the Members in respect of any such Alternative Investment Vehicle) may be governed by the local law of the jurisdiction of organization of such Alternative Investment Vehicle. Each of the Investor Parties and their representatives and Affiliates other than any Management Incentive Member (collectively, the "*Institutional Investors*") will be permitted to assign its rights and obligations as a participant in an Alternative Investment Vehicle to an Affiliate of such Member (any assignee, an "*Affiliate AIV Member*"). If an Institutional Investor assigns its rights and obligations to an Affiliate AIV Member, the interest of the Affiliate AIV Member in an Alternative Investment Vehicle will be treated as an interest held by the Member that assigned its rights to the Affiliate AIV Member for purposes of any calculations under this Agreement and the agreement governing the Alternative Investment Vehicle, including for purposes of determining Capital Contributions and rights to distributions and amounts thereof. If any Potentially Restricted Member elects to become an Opt-Out Member with respect to any Alternative Investment Vehicle, such election shall not affect such Potentially Restricted Member's Capital Commitment hereunder, and the Board of Managers shall thereafter make such adjustments, as the Board of Managers may reasonably determine, to future Capital Calls made by the Company to adjust for such Potentially Restricted Member's election not to make Capital Contributions to such Alternative Investment Vehicle.

1.10 Company History.

As of the Effective Date, other than the negotiation, execution and delivery of the First Amended and Restated Agreement, the other agreements contemplated thereby or entered into in connection with the closing of the Development Agreement, the Company had not (a) conducted any business, (b) incurred any expenses, obligations or liabilities (whether accrued, absolute, contingent, unliquidated or otherwise, whether or not known to the Company and whether due or to become due and regardless of when asserted) or (c) entered into any contracts or agreements. Further, as of the Effective Date, the Company (i) had not issued any Interests other than 510,000 Common Units issued to Clark on March 19, 2012, (ii) did not own any assets other than contributed cash in exchange for such Common Units issued to Clark, (iii) had not violated

any laws or governmental rules or regulations and (iv) had not participated in any merger, reorganization, spin-off or similar transaction.

ARTICLE 2
DEFINITIONS AND REFERENCES

2.1 Defined Terms.

When used in this Agreement, the following terms shall have the respective meanings set forth below:

"*AAA*" has the meaning given to such term in Section 9.4.

"*Act*" means the Delaware Limited Liability Company Act, 6 Del. C. Section 18-101, et seq., as amended, supplemented or restated from time to time, and any successor to such statute.

"*Affiliate*" means, as to a specified Person, any other Person directly or indirectly Controlling, Controlled by or under common Control with, such specified Person. For purposes of this Agreement, the Jefferies Parties, on the one hand, and Management and the Beato Family Trust, on the other, shall not be deemed "Affiliates."

"*Affiliate AIV Member*" has the meaning given to such term in Section 1.9.

"*Aggregate Call Amount*" has the meaning given to such term in Section 3.2(c).

"*Agreement*" has the meaning given to such term in the introductory paragraph of this Agreement.

"*Allocable Share*" has the meaning given to such term in Section 4.2(a).

"*Alternative Investment Vehicle*" means any investment vehicle formed pursuant to Section 1.9.

"*Approved Budget*" means a budget described in Section 7.4(c) and approved pursuant thereto.

"*Approved Party*" means any Person that becomes a Member and its representatives and Affiliates.

"*Atwood*" means John P. Atwood.

"*Atwood Employment Agreement*" means the Employment Agreement between Exaro Services and Atwood, as entered into as of December 11, 2009, as amended as of the Effective Date, and as amended from time to time.

"*Available Cash*" means, at any time of determination: (a) all cash and cash equivalents of the Company on hand at such time; less (b) the sum of all reserves in such amounts as the Board of Managers determines to be necessary or advisable to (i) provide for the proper conduct of the business of the Company (including capital expenditures and Tax Distributions) for the

180 days following the time of determination and (ii) comply with all applicable law and any covenants under any loan agreements, security agreements or other agreements to which the Company is a party.

"*Award Letter*" has the meaning given to such term in Section 3.4(a).

"*BB*" has the meaning given to such term in Section 11.10(c).

"*Beato*" means Christopher L. Beato.

"*Beato Employment Agreement*" means the Employment Agreement between Exaro Services and Beato, as entered into as of December 11, 2009, as amended as of the Effective Date, and as amended from time to time.

"*Beato Family Trust*" means the Beato Family 2008 Trust.

"*BHC Affiliate*" has the meaning given to such term in Section 3.7(a).

"*BHC Group*" has the meaning given to such term in Section 3.7(a).

"*BHC Member*" means a Member that is a bank holding company as defined in the BHCA, or a non-bank subsidiary of such a bank holding company. Each of Union Bank and Wells Fargo is a BHC Member.

"*BHCA*" means the Bank Holding Company Act of 1956, as amended, or any successor to such act, and the rules and regulations promulgated thereunder.

"*Blocker Corporation*" has the meaning given to such term in Section 9.8(e).

"*Board of Managers"* or "*Board*" means the governing body established to govern the business and affairs of the Company as provided in Article 5. "*Business Day*" means each day of the week except Saturdays, Sundays and days on which banking institutions are authorized by law to close in the State of Texas.

"*Business Opportunity*" has the meaning given to such term in Section 6.5(b).

"*Capital Account*" means the capital account maintained for each Member pursuant to the requirements of Section C.1.2 of Exhibit C.

"*Capital Call*" has the meaning given to such term in Section 3.2(b).

"*Capital Commitment*" means, for any Member at any particular time the total capital commitment of such Member set forth opposite its name on Exhibit A-1 under the column labeled "Total Capital Commitment."

"*Capital Contribution*" means for any Member at any particular time the aggregate of the dollar amount of any cash and the Net Agreed Value of any property contributed (or deemed contributed) to the Company, as such Net Agreed Value is determined by the Board of Managers in its sole discretion.

"*Capital Contribution Ratio*" means, for each Common Unitholder as of any date of determination, a fraction (expressed as a percentage) the numerator of which is such Common Unitholder's Capital Contribution as of such date and the denominator of which is the sum of the Capital Contributions of all of the Common Unitholders as of such date. The Capital Contribution Ratio of all of the Common Unitholders shall be recomputed whenever a change in Capital Contributions occurs by reason of the admission of additional Common Unitholders from time to time or an increase or decrease in an existing Member's Capital Contributions in accordance with the terms of this Agreement.

"*Capital Stock*" means any and all shares, interests, participations or other equivalents (however designated) of capital stock of a corporation, any and all equivalent ownership interests in a Person (other than a corporation), and any and all warrants, options, or other rights to purchase or acquire any of the foregoing.

"*CEO*" means the Chief Executive Officer of the Company, as determined by the Board of Managers. The initial CEO will be Beato.

"*Certificate*" has the meaning given to such term in the introductory paragraph.

"*Clark*" means Scott R. Clark.

"*Clark Employment Agreement*" means the Employment Agreement between Exaro Services and Clark, as entered into as of the Effective Date, and as amended from time to time.

"*Clark Interests*" has the meaning given to such term in Section 6.4(b)(v).

"*Clark Note*" means the promissory note issued to the Company by Clark on the Initial Funding Date, secured by interests in the Company.

"*Code*" means the Internal Revenue Code of 1986, as amended and in effect from time to time, as interpreted by the applicable regulations thereunder. Any reference herein to a specific section or sections of the Code shall be deemed to include a reference to any corresponding provision of future law.

"*Commitment Cash Call*" has the meaning given to such term in the Development Agreement.

"*Common Units*" means the Interest granted to a Member in exchange for such Member's Capital Contributions. For purposes of clarification, a Common Unit shall not include any Interest attributable to Management Incentive Units.

"*Common Unitholder*" means a Member holding of record Common Units.

"*Company*" has the meaning given to such term in the introductory paragraph of this Agreement.

"*Company Business Opportunity*" has the meaning given to such term in Section 6.5(b).

"*Company Manager*" has the meaning given to such term in Section 10.1(c).

"*Confidential Information*" means any information that is currently held by the Company or is hereafter acquired, developed or used by the Company relating to business opportunities or other geological, geophysical, engineering, operational, economic, financial, management or other aspects of the business, operations, properties or prospects of the Company, whether oral or in written form, but shall exclude any information that (a) has become part of common knowledge or understanding in the oil and natural gas industry or becomes generally available to the public (other than from wrongful disclosure in violation of this Agreement, any confidentiality agreement, any Employment Agreement or any Award Letter), (b) was rightfully in the possession of a Member, Manager or Officer prior to the Effective Date (or, in the case of an employee of the Company, any of its Subsidiaries or the Management Company prior to the effective date of his or her employment with the Company, any of its Subsidiaries or the Management Company) from a source unrelated to the Company or (c) obtained by such Member from a third person who, to the knowledge of such Member, is not prohibited from transmitting the information to such Member by a contractual obligation to the Company or any of its Subsidiaries). The foregoing is not intended to reduce or otherwise modify the confidentiality obligations of any Person under any applicable Employment Agreement.

"*Contaro*" means Contaro Company, a Delaware corporation.

"*Contaro Managers*" has the meaning given to such term in Section 5.2(b).

"*Control*" or "*Controlling*" means the possession, directly or indirectly, through one or more intermediaries, of the following: (a) in the case of a corporation, more than 50% of the outstanding voting securities thereof; (b) in the case of a limited liability company, partnership, limited partnership or joint venture, the right at any time to more than 50% of the distributions therefrom (including liquidating distributions); (c) in the case of a trust or estate, more than 50% of the beneficial interest therein or the power or authority, through ownership of voting securities, by contract or otherwise, to direct the management, activities or policies of such trust or estate; (d) in the case of any other Entity, more than 50% of the economic or beneficial interest therein; or (e) in the case of any Entity, the power or authority, through ownership of voting securities, by contract or otherwise, to direct the management, activities or policies of the Entity.

"*Conversion*" has the meaning given to such term in Section 9.8(c).

"*Conversion Consideration*" has the meaning given to such term in Section 9.8(c).

"*Covered Person*" means any Member Covered Person, any Manager Covered Person and any Officer Covered Person.

"*Cumulative Taxable Income*" means the sum of (i) the amount, if any, by which items of income and gain (other than items included in net capital gain or net capital loss) allocated for federal income tax purposes pursuant to Exhibit C through the end of the current Fiscal Quarter exceeds the items of loss and deduction (other than items included in net capital gain or net capital loss) allocated for federal income tax purposes pursuant to Exhibit C, through the end of the current Fiscal Quarter and (ii) the amount, if any, by which net capital gain allocated for

federal income tax purposes pursuant to Exhibit C through the end of the current Fiscal Quarter exceeds net capital loss allocated for federal income tax purposes pursuant to Exhibit C through the end of the current Fiscal Quarter.

"*Current MIU Distribution Amount*" has the meaning given to such term in Section 4.2(b)(ii).

"*DD*" has the meaning given to such term in Section 11.10(d).

"*Deemed Exercise Price*" means, with respect to a Management Incentive Unit, $0.00 unless a different amount is expressly set forth as such in the Award Letter granting such Management Incentive Unit.

"*Default Interests*" shall have the meaning given to such term in Section 3.2(d)(ii)(D).

"*Default Price*" shall have the meaning given to such term in Section 3.2(d)(ii)(D).

"*Default Rights Notice*" shall have the meaning given to such term in Section 3.2(d)(ii)(D).

"*Default Rights Notice Period*" shall have the meaning given to such term in Section 3.2(d)(ii)(D).

"*Defaulting Member*" has the meaning given to such term in Section 3.2(d).

"*Deemed Tax Rate*" means, with respect to a Fiscal Quarter, the percentage reasonably determined by the Board of Managers to reflect the highest marginal combined federal, state and local income tax rate applicable to individuals or corporations in effect as of the end of such Fiscal Quarter, and shall be applied to all Members regardless of their particular tax status.

"*Development Agreement*" has the meaning given to such term in Section 1.3.

"*Drilling Notice*" has the meaning given to such term in the Development Agreement.

"*Disability*" means, with respect to a Management Incentive Member, the disability of such Management Incentive Member as evidenced by an inability to perform the duties and responsibilities required of such Member under any Employment Agreement due to a physical and/or mental disability for a period of 90 consecutive days or 180 days, whether or not consecutive, during any 12 month period.

"*Drag-Along Member*" has the meaning given to such term in Section 9.6(a).

"*Drag-Along Notice*" has the meaning given to such term in Section 9.6(a).

"*Drag-Along Notice Period*" has the meaning given to such term in Section 9.6(a).

"*Drag-Along Transaction*" has the meaning given to such term in Section 9.6(a).

"*Dragging Member*" has the meaning given to such term in Section 9.6(a).

"*Effective Date*" means March 31, 2012.

"*Eligible Investor*" has the meaning given to such term in Section 3.3.

"*Employee Member*" has the meaning given to such term in Section 6.5(c).

"*Employment Agreement*" has the meaning given to such term in Section 3.4(a).

"*Encana*" has the meaning given to such term in Section 1.3.

"*Entity*" means any Person other than a natural person.

"*Estimated MIU Distribution Amount*" has the meaning given to such term in Section 4.2(b)(ii).

"*Exaro II*" means Exaro Energy II LLC, a Delaware limited liability company.

"*Exaro Services*" means Exaro Energy Services, LLC, a Delaware limited liability company and Subsidiary of the Company.

"*Fair Market Value*" means, as of any date of determination, (a) when used with respect to an Interest, including a Repurchase Interest, the amount of cash and fair market value of property that would be received by the holder of such Interest if the assets of the Company were sold for fair market value (giving no credit to any going concern value of the Company) as of such date as determined in good faith by the Board of Managers, all debts, liabilities and obligations were fully paid and satisfied or adequate provision was made therefor, and all assets of the Company remaining after satisfying such debts, liabilities and obligations were distributed to the Members in accordance with Section 8.2 and (b) when used with respect to any other asset, the amount of cash a willing buyer would pay a willing seller for that asset at that time in an arm's length transaction as determined in good faith by the Board of Managers.

"*Final Exit Event*" means: (a) a dissolution or liquidation of the Company under Article 8; (b) the consolidation, reorganization, merger or any other similar transaction involving the Company and any other Person and in which Interests are changed into or exchanged for cash, securities or other property, other than any such transaction in which both (i) (A) the outstanding Interests are changed into or exchanged for securities of the surviving Person or its parent and (B) the holders of the Interests immediately prior to such transaction own, directly or indirectly, not less than a majority of the outstanding securities of the surviving Person or its parent immediately after such transaction and (ii) (A) the outstanding Interests with voting rights under this Agreement are changed into or exchanged for securities of the surviving Person or its parent and (B) the holders of such Interests immediately prior to such transaction own, directly or indirectly, not less than a majority of the outstanding voting securities of the surviving Person or its parent immediately after such transaction; (c) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the Company's and its Subsidiaries' assets taken as a whole to any other Person promptly followed by a dissolution or liquidation of the Company under Article 8 or (d) the consummation of a Drag-Along Transaction. For the avoidance of doubt, an Initial Public Offering shall not be deemed to be a Final Exit Event.

"*First Amended and Restated Agreement*" has the meaning given to such term in the introductory paragraphs of this Agreement.

"*First Flip Sharing Ratio*" means, as of any date of determination:

(a) with respect to any Common Unitholder, solely with respect to the Common Units held by such Common Unitholder (and not with respect to any Management Incentive Units held by such Common Unitholder), the product of (i) such Common Unitholder's Capital Contribution Ratio as of such date and (ii) 90%; and

(b) with respect to any Management Incentive Member, solely with respect to the Management Incentive Units held by such Management Incentive Member (and not with respect to any Common Units held by such Management Incentive Member) the product of (i) such Management Incentive Member's MIU Percentage and (ii) 10%.

"*First Threshold*" has the meaning given to such term in Section 4.2(a)(i).

"*Fiscal Quarters*" means the three month periods ending on March 31, June 30, September 30 and December 31 of each Fiscal Year.

"*Fiscal Year*" means the 12-month period ending December 31 of each year; provided that the initial Fiscal Year is the period from March 19, 2012 and ended on December 31, 2012 and the last Fiscal Year shall be the period beginning on January 1 of the calendar year in which the final liquidation and termination of the Company is completed and ending on the date such final liquidation and termination is completed (to the extent any computation or other provision hereof provides for an action to be taken on a Fiscal Year basis, an appropriate proration or other adjustment shall be made in respect of the initial and final Fiscal Years to reflect that such periods are less than full calendar year periods).

"*Fourth Flip Sharing Ratio*" means, as of any date of determination:

(a) with respect to any Common Unitholder, solely with respect to the Common Units held by such Common Unitholder (and not with respect to any Management Incentive Units held by such Common Unitholder), the product of (i) such Common Unitholder's Capital Contribution Ratio as of such date and (ii) 75%; and

(b) with respect to any Management Incentive Member, solely with respect to the Management Incentive Units held by such Management Incentive Member (and not with respect to any Common Units held by such Management Incentive Member) the product of (i) such Management Incentive Member's MIU Percentage and (ii) 25%;

"*Fourth Threshold*" has the meaning given to such term in Section 4.2(a)(iv).

"*Fully-Funded Percentage Interest*" means, with respect to any Member as of any time of determination, the percentage obtained by dividing (a) the number of Common Units held by such Member plus the number of Common Units, if any, that are issuable to such Member upon the full funding of such Member's Remaining Capital Commitment by (b) the number of outstanding Common Units (other than Common Units held by Defaulting Members) plus the

number of Common Units, if any, that are issuable to all Members upon the full funding of all Members' Remaining Capital Commitments. For the avoidance of doubt, each Defaulting Members' Remaining Capital Commitment shall be deemed to be $0.00 for purposes of this definition.

"*GAAP*" means generally accepted United States accounting principles and policies in effect from time to time, applied on a consistent basis.

"*Gross Asset Value*" has the meaning given to such term in Exhibit C.

"*Initial Budget*" means the initial operating and capital expenditure budget of the Company attached hereto as Exhibit E.

"*Initial Funding Date*" means April 20, 2012.

"*Initial Public Offering*" means an initial public offering of interests in the Company or any other related entity pursuant to a Conversion.

"*Initiating Member*" has the meaning given to such term in Section 9.6(b).

"*Institutional Investors*" has the meaning given to such term in Section 1.9.

"*Interest*" means a membership interest (including a membership interest attributable to Management Incentive Units) in the Company with all the rights, interests and obligations of a Member in the Company under this Agreement and the Act, including (a) the right of a Member to receive allocations of income and loss and distributions or liquidation proceeds under this Agreement, (b) all management rights, voting rights or rights to consent provided under this Agreement and (c) any obligation to make Capital Contributions as set forth in this Agreement.

"*Interim Distribution*" has the meaning given to such term in Section 4.2(b)(ii).

"*Internal Restructure*" means any re-formation, Conversion, transfer of assets, transfer of membership interests or other securities, merger, incorporation, liquidation or other transaction of, or relating to, or affecting the Company, completed in compliance with Section 9.8.

"*Investor Parties*" means each of Contaro, the Sageview Parties, the Jefferies Parties, Union Bank and Wells Fargo.

"*IRR*" at a given time for a Common Unitholder means the discount rate at which the present value of the distributions received by that Common Unitholder from the Company pursuant to Section 4.2 up to such time, discounted to the Initial Funding Date equals the present value of the Capital Contributions as and when made by the Common Unitholders to the Company, discounted at such discount rate from the date made to the Initial Funding Date; provided that such rate shall be calculated using the XIRR function on Microsoft Excel.

"*Jefferies IV*" means Jefferies Capital Partners IV L.P., a Delaware limited partnership.

"*Jefferies Management IV*" means JCP Partners IV LLC, a Delaware limited liability company.

"*Jefferies Managers*" has the meaning given to such term in Section 5.2(d).

"*Jefferies Parallel IV*" means Jefferies Employee Partners IV LLC, a Delaware limited liability company.

"*Jefferies Parties*" means Jefferies IV, Jefferies Management IV and Jefferies Parallel IV.

"*Law*" means any applicable constitutional provision, statute, act, code (including the Code), law, regulation, rule, ordinance, order, decree, ruling, proclamation, resolution, judgment, decision, declaration, or interpretative or advisory opinion or letter of a governmental authority.

"*Management*" means Beato, Atwood and Clark.

"*Management Company*" means Exaro Services or any other entity providing management, administrative and operational services to the Company or its Subsidiaries.

"*Management Incentive Member*" means a Member who holds of record a Management Incentive Unit. To the extent a Member holds Common Units and one or more Management Incentive Units, such Member will be treated as a Management Incentive Member only with respect to the Management Incentive Units held thereby.

"*Management Incentive Unit*" means a "Management Incentive Unit" as described in the Plan and issued in accordance therewith. Management Incentive Units are not Common Units.

"*Management Manager*" has the meaning given to such term in Section 5.2(e).

"*Manager*" means any individual duly elected and serving on the Board of Managers of the Company.

"*Manager Covered Person*" means (a) each current and former Manager (solely in such Person's capacity as a Manager) and (b) each Person not identified in clause (a) of this definition who is or was a director or manager of any Subsidiary of the Company and who the Board expressly designates as a Manager Covered Person in a written resolution.

"*Managing Member*" means the CEO; provided, that if no CEO shall then be in office, the Managing Member shall be such other person performing similar functions as determined by the Board of Managers. Beato is the initial Managing Member.

"*Marketable Securities*" means securities that are (a) traded on an established U.S. national or non-U.S. securities exchange or (b) reported through an established non-U.S. over-the-counter trading system or (c) otherwise traded over-the-counter or purchased and sold in transactions effected pursuant to Rule 144A under the Securities Act, that in each case are not subject to restrictions on Transfer under the Securities Act or other applicable securities laws (other than the restriction under Rule 144A limiting Transfers solely to qualified institutional

buyers) or subject to contractual restrictions on Transfer other than reasonable and customary lock-up provisions that do not exceed 180 days in duration.

"*Maximum Quarterly Company Tax Distribution*" means, with respect to a Fiscal Quarter, an amount equal to the product of (a) the Deemed Tax Rate with respect to such Fiscal Quarter and (b) the increase, if any, in the Company's Cumulative Taxable Income during such Fiscal Quarter.

"*Member*" means, as of any date of determination, any Person that is a record holder of an Interest as of such date.

"*Member Covered Person*" means (a) each Member (including in its capacity as tax matters partner hereunder, if applicable), (b) each Member's officers, directors, liquidators, partners, equityholders, managers and members, (c) each Member's Affiliates (other than the Company and its Subsidiaries) and each of their respective officers, directors, liquidators, partners, equityholders, managers and members and (d) any representatives, agents or employees of any Person identified in clauses (a)-(d) of this definition who the Board expressly designates as a Member Covered Person in a written resolution.

"*Member Manager*" has the meaning given to such term in Section 10.1(b).

"*MIU Percentage*" means, as of any date of determination for any Management Incentive Member, a percentage the numerator of which equals the number of Management Incentive Units held of record by such Management Incentive Member as of such date and the denominator of which equals the total number of authorized Management Incentive Units (whether or not outstanding) as of such date. If the sum of the percentages with respect to all Management Incentive Members, as determined in the prior sentence, is less than 100%, the amount by which such sum is less than 100% is referred to herein as the "*Unallocated MIU Percentage*". For purposes of this definition, Management Incentive Units that have been forfeited to or repurchased by the Company shall be considered authorized but not outstanding so long as such Management Incentive Units continue to be held by the Company.

"*MLB*" has the meaning given to such term in Section 11.10(a).

"*Net Agreed Value*" means (a) in the case of any property contributed to the Company, the Gross Asset Value of such property reduced by any liabilities either assumed by the Company upon such contribution or to which such property is subject when contributed and (b) in the case of any property distributed to the Members by the Company, the Gross Asset Value of such property at the time such property is distributed, reduced by any indebtedness either assumed by the Members upon such distribution or to which such property is subject at the time of distribution, in either case, as determined under section 752 of the Code.

"*Non-Voting Interests*" has the meaning given to such term in Section 3.7.

"*Offer*" has the meaning given to such term in Section 6.4(c)(iii)(A).

"*Officer"* means an officer of the Company.

"*Officer Covered Person*" (a) each current and former Officer (solely in such Person's capacity as an Officer) and (b) each Person not identified in clause (a) of this definition who is or was an officer or employee of any Subsidiary of the Company and who the Board of Managers expressly designates as an Officer Covered Person in a written resolution.

"*Old Interests*" has the meaning given to such term in Section 9.7(c).

"*Opt-Out Election*" has the meaning given to such term in Section 6.7.

"*Opt-Out Member*" has the meaning given to such term in Section 1.9.

"*Other Investment*" has the meaning given to such term in Section 6.5(a).

"*Payment Default*" has the meaning give to such term in Section 3.2(d).

"*Payment Notice*" has the meaning given to such term in Section 3.2(c).

"*Permitted Transfer*" means (a) with respect to any Institutional Investor, any Transfer (i) by such Member to its Affiliates, partners, constituent members or other equity owners and any Transfer by any such Affiliates, partners, constituent members or other equity owners to any Affiliates thereof (provided, for these purposes, the term "Affiliate" shall not include any portfolio company (or direct or indirect holding company or subsidiary thereof)) or members, partners or other equity owners thereof, (ii) by such Member's general partner to its members or partners, or (iii) by such Member to another fund or investment entity managed by an Affiliate of such Member, (b) with respect to any Member, any Transfer or forfeiture to the Company and (c) with respect to each Member that is a natural person, any Transfer to such Member's spouse, siblings, lineal descendants, parents or in-laws or to any Entity the sole owners of which are such transferring Member, such transferring Member's spouse, siblings, lineal descendants, parents or in-laws; provided, that with respect to Transfers under this clause (c), such Member must retain control (by agreement or otherwise) to all voting rights relating to the Interest so transferred and such Interest shall remain fully subject to the terms and provisions of this Agreement.

"*Permitted Transferee*" means, with respect to any Member, any Person that receives, directly or indirectly, interests from such Member pursuant to a Permitted Transfer.

"*Person*" means an individual, an estate or a corporation, partnership, joint venture, limited partnership, limited liability company, trust, association or any other entity.

"*Plan*" has the meaning given to such term in Section 3.4(a).

"*Potentially Restricted Member*" means each of Union Bank and Wells Fargo.

"*Preemptive Rights Notice Period*" has the meaning given to such term in Section 3.3.

"*Recalculation Event*" has the meaning given to such term in Section 3.7(a).

"*Remaining Capital Commitment*" means for any Member at any particular time the difference between the Capital Commitment for such Member and the Capital Contributions for such Member up to such time.

"*Remaining Default Interests*" shall have the meaning given to such term in Section 3.2(d)(ii)(D).

"*Renounced Business Opportunity*" has the meaning given to such term in Section 6.5(b).

"*Repurchase Interest*" has the meaning given to such term in Section 9.4.

"*Repurchase Interest Holder*" has the meaning given to such term in Section 9.4.

"*Repurchase Notice*" has the meaning given to such term in Section 9.4.

"*Repurchase Option*" has the meaning given to such term in Section 9.4.

"*Repurchase Option Exercise Notice*" has the meaning given to such term in Section 9.4.

"*Repurchase Price*" has the meaning given to such term in Section 9.4.

"*Retained Amount*" has the meaning given to such term in Section 4.2(b)(ii).

"*Retention Exercise Notice*" has the meaning given to such term in Section 9.4.

"*Right of First Refusal*" has the meaning given to such term in Section 9.3(a).

"*Right of First Refusal Notice*" has the meaning given to such term in Section 9.3(a).

"*Right of First Refusal Notice Period*" has the meaning given to such term in Section 9.3(a).

"*Right of First Refusal Option*" has the meaning given to such term in Section 9.3(a).

"*Right of First Refusal Units*" has the meaning given to such term in Section 9.3(a).

"*ROFO Consummation Deadline*" has the meaning given to such term in Section 9.7(c).

"*ROFO Initiator*" has the meaning given to such term in Section 9.7(a).

"*ROFO Notice*" has the meaning given to such term in Section 9.7(b).

"*ROFO Offer*" has the meaning given to such term in Section 9.7(b).

"*ROFO Offer Price*" has the meaning given to such term in Section 9.7(b).

"*ROFO Offeror*" has the meaning given to such term in Section 9.7(b).

"*Russell*" means Branch J. Russell.

"*Sageview A*" means Sageview Capital Partners (A), L.P., a Delaware limited partnership.

"*Sageview B*" means Sageview Capital Partners (B), L.P., a Delaware limited partnership.

"*Sageview C*" means Sageview Energy Partners (C) Investments, L.P., a Delaware limited partnership.

"*Sageview GenPar*" means Sageview Capital GenPar, L.P., a Delaware limited partnership.

"*Sageview Parties*" means Sageview A, Sageview B, Sageview C and Sageview GenPar.

"*Sageview Managers*" has the meaning given to such term in Section 5.2(c).

"*Second Amendment Date*" has the meaning given to such term in the introductory paragraph.

"*Second Flip Sharing Ratio*" means, as of any date of determination:

(a) with respect to any Common Unitholder, solely with respect to the Common Units held by such Common Unitholder (and not with respect to any Management Incentive Units held by such Common Unitholder), the product of (i) such Common Unitholder's Capital Contribution Ratio as of such date and (ii) 80%; and

(b) with respect to any Management Incentive Member, solely with respect to the Management Incentive Units held by such Management Incentive Member (and not with respect to any Common Units held by such Management Incentive Member) the product of (i) such Management Incentive Member's MIU Percentage and (ii) 20%.

"*Second Threshold*" has the meaning given to such term in Section 4.2(a)(ii).

"*Securities Act*" means the Securities Act of 1933, as amended.

"*Service Interests*" has the meaning given to such term in Section 5.14(c).

"*Services Agreement*" means the Services Agreement, dated as of March 31, 2012, by and among the Company, Exaro Services and Exaro II or any other services agreement by and between the Company and the Management Company.

"*Sharing Ratio*" means the Capital Contribution Ratio, the First Flip Sharing Ratio, the Second Flip Sharing Ratio, the Third Flip Sharing Ratio and the Fourth Flip Sharing Ratio, whichever applies at the time such reference is made.

"*Subsidiary*" means, with respect to the Company, (a) any corporation or other entity (including a limited liability company) a majority of the Capital Stock of which having ordinary voting power to elect a majority of the board of directors or other Persons performing similar functions is at the time owned, directly or indirectly, with power to vote, by the Company, or any

direct or indirect Subsidiary of the Company or (b) a partnership in which the Company or any direct or indirect Subsidiary is a general partner.

"*Subject Assets*" has the meaning given to such term in Section 6.4(b)(ii).

"*Supermajority Member Approval*" means the affirmative vote of each Member or Investor Party (excluding any Defaulting Member) with a Capital Commitment of at least $35 million; for the avoidance of doubt, Contaro, the Jefferies Parties (collectively, and together with their Affiliates that are Permitted Transferees) and the Sageview Parties (collectively, and together with their Affiliates that are Permitted Transferees) each constitute an Investor Party for purposes of such calculation.

"*Tag Percentage*" has the meaning given to such term in Section 9.6(b).

"*Tag-Along Notice*" has the meaning given to such term in Section 9.6(b).

"*Tag-Along Response Notice*" has the meaning given to such term in Section 9.6(b).

"*Tag-Along Right*" has the meaning given to such term in Section 9.6(b).

"*Tag-Along Transaction*" has the meaning given to such term in Section 9.6(b).

"*Tagging Member*" has the meaning given to such term in Section 9.6(b).

"*Tax Distribution*" has the meaning given to such term in Section 4.3.

"*Third Flip Sharing Ratio*" means, as of any date of determination:

(a) with respect to any Common Unitholder, solely with respect to the Common Units held by such Common Unitholder (and not with respect to any Management Incentive Units held by such Common Unitholder), the product of (i) such Common Unitholder's Capital Contribution Ratio as of such date and (ii) 77%; and

(b) with respect to any Management Incentive Member, solely with respect to the Management Incentive Units held by such Management Incentive Member (and not with respect to any Common Units held by such Management Incentive Member) the product of (i) such Management Incentive Member's MIU Percentage and (ii) 23%.

"*Third Threshold*" has the meaning given to such term in Section 4.2(a)(iii).

"*Third-Party Indemnitees*" has the meaning given to such term in Section 10.2(f).

"*Third-Party Indemnitors*" has the meaning given to such term in Section 10.2(f).

"*Threshold*" means any of the First Threshold, Second Threshold, Third Threshold or Fourth Threshold, as applicable.

"*Tier*" has the meaning given to such term in Section 4.2(a).

"*Total Distribution*" means, as of any date of determination and with respect to each Common Unitholder, the total amount of cash and the Net Agreed Value (as of the date of actual distribution) of all property distributed to such Common Unitholder as of such date of determination pursuant to Section 4.2(a) or deemed distributed to such Common Unitholder under Section 4.2(a) by reason of the distribution rules in Section 4.2(b).

"*Transaction Documents*" means the Services Agreement, the Beato Employment Agreement, the Atwood Employment Agreement, the Clark Employment Agreement and the Clark Note.

"*Transfer*" or "*Transferred"* means to transfer, sell, assign, pledge, hypothecate, give, create a security interest in or lien on, place in trust (voting or otherwise), assign or in any other way encumber or dispose of, directly or indirectly and whether or not by operation of law or for value, any Interest.

"*Treasury Regulation*" means any temporary or final income tax regulation issued by the United States Treasury Department.

"*Unallocated MIU Percentage*" has the meaning given to such term in the definition of "MIU Percentage."

"*Union Bank*" means UnionBanCal Equities, Inc.

"*VCOC Amendment*" has the meaning given to such term in Section 11.5(b).

"*VE*" has the meaning given to such term in Section 11.10(b).

"*Wells Fargo*" means Wells Fargo Central Pacific Holdings, Inc., a California corporation.

"*Withheld Amount*" has the meaning given to such term in Section 4.2(a)(vii).

2.2 References and Titles.

All references in this Agreement to articles, sections, subsections, other subdivisions and exhibits refer to corresponding articles, sections, subsections, other subdivisions and exhibits of this Agreement unless expressly provided otherwise. Titles appearing at the beginning of any of such subdivisions are for convenience only and shall not constitute part of such subdivisions and shall be disregarded in construing the language contained in such subdivisions. The words "this Agreement," "herein," "hereof," "hereby," "hereunder" and words of similar import refer to this Agreement as a whole and not to any particular subdivision unless expressly so limited. The term "including" shall be deemed followed by the words, "without limitation." Pronouns in masculine, feminine and neuter genders shall be construed to include any other gender, and words in the singular form shall be construed to include the plural and vice versa, unless the context otherwise requires.

ARTICLE 3
ADMISSION OF MEMBERS; CAPITAL CONTRIBUTIONS

3.1 Admission of Members.

(a) *Existing Members.* Each Person who was a signatory to the First Amended and Restated Agreement and who is listed on Exhibits A-1 or A-2, each other Person who is a signatory to this Agreement and each other Person who joins in this Agreement pursuant to a joinder agreement, substantially in the form attached hereto as Exhibit F or as otherwise approved by the Company, is hereby admitted as a Member as of the Effective Date, the Second Amendment Date, and as of the date of such joinder agreement, respectively.

(b) *Additional Members.* In addition to the Persons who became Members pursuant to Section 3.1(a) above, the following Persons shall be deemed to be Members and shall be admitted as Members without any further action by the Company: (i) any Person to whom Common Units or Management Incentive Units are Transferred by a Member, so long as such Transfer is made in compliance with this Agreement (including Section 9.5) and, if applicable, the Plan (and, in all cases described in this clause (i), such transferee shall be deemed a Member as of the first day of the calendar month following the day on which such Transfer occurs or such earlier date as the Company and such transferee shall agree) and (ii) any Person to whom the Company issues Common Units or Management Incentive Units after the Effective Date in compliance with this Agreement or the First Amended and Restated Agreement and, if applicable, the Plan.

(c) *Cessation of a Member.* Any Member admitted or deemed admitted as a Member pursuant to Section 3.1(a) or Section 3.1(b) shall cease to have the rights of a Member under this Agreement at such time that such Person is no longer a record owner of any Interests, but such Person shall remain bound by all of the terms of Article 11 as well as by Section 7.5.

3.2 Capital Contributions of Members; Defaulting Members.

(a) *Contributions*. Each Common Unitholder (or its predecessor as a Common Unitholder) has made capital contributions and, in the case of Clark, issued the Clark Note to the Company in the amount opposite its name in the column labeled "Existing Capital Contributions" on Exhibit A-1 and each Common Unitholder (or its predecessor as a Common Unitholder) has received Common Units at a fixed price of $1.00 per Common Unit in the amount opposite its name in the column labeled "Existing Common Units" on Exhibit A-1.

(b) *Additional Capital Contributions*. The Common Unitholders shall make additional Capital Contributions in proportion to their Capital Commitments in such aggregate amounts and at such times as shall be recommended by the Managing Member on an as-needed basis and approved by the Board of Managers (each, a "*Capital Call*") and receive Common Units at a fixed price of $1.00 per Common Unit; provided that, the Managing Member shall attempt to make a recommendation for any Capital Call not more than once per quarter and the Managing Member shall plan any Capital Call to coincide with the Company's funding requirements under the Development Agreement or otherwise; and provided further that, no Common Unitholder shall be obligated to make additional Capital Contributions (i) in excess of such Common Unitholder's Remaining Capital Commitment, (ii) after the fifth anniversary of the Effective Date (subject to any extensions (A) as approved by the Members pursuant to a

Supermajority Member Approval and (B) for an amount of time equal to any extension of the Development Agreement pursuant to the terms thereof), (iii) following an Initial Public Offering or (iv) following any Final Exit Event.

(c) *Additional Capital Call Procedures*. Subject to the limitations and other terms of this Section 3.2, upon the instruction and approval of the Board of Managers, the Company shall issue notices from time to time to require the Common Unitholders to make Capital Contributions at such times and in such amounts as specified in the applicable notice (each, a "*Payment Notice*"). Each Payment Notice sent by the Company to each Common Unitholder shall specify the following: (i) the aggregate amount in integral multiples of $500,000 being called by the Company (the "*Aggregate Call Amount*"), (ii) such Common Unitholder's pro rata share thereof based on such Common Unitholder's Remaining Capital Commitments in proportion to the Remaining Capital Commitments of all the Members (subject to the last sentence of Section 1.9), (iii) the date by which such Capital Contribution is required to be funded, which shall be not less than 15 Business Days after such notice is given to the Common Unitholders and (iv) wiring instructions for the depository institution and account into which such Capital Contribution shall be made.

(d) *Default.*

(i) If any Member fails for any reason to make a Capital Contribution required in any Capital Call for a period ending on the later to occur of (A) 10 Business Days after the due date thereof, or (B) two Business Days after the Company has provided written notice of such failure to such Member (such failure, a "*Payment Default*"), such Member and each of its Permitted Transferees and Affiliates that then holds any Interests, and, in the event such Member is itself a Permitted Transferee, the assignor that directly or indirectly assigned such Permitted Transferee its Interest shall each be a "*Defaulting Member*." Notwithstanding anything to the contrary, Contaro shall not be a Defaulting Member with respect to any Payment Default of the Jefferies Parties that relates to the Remaining Capital Commitment Transferred from Contaro ultimately to the Jefferies Parties in connection with the exercise of the Exaro II Jonah Option (as defined in the First Amended and Restated Agreement).

(ii) Effective as of the occurrence of a Payment Default, such Defaulting Member will be subject to one or more of the following remedies at the discretion of the Board of Managers (excluding any Manager(s) designated by the Defaulting Member):

(A) loss of all rights to designate Managers (including related voting power) or Board Observers under this Agreement;

(B) loss of the right (but not the obligation) to participate in future Capital Calls and to fund any Remaining Commitment;

(C) forfeiture of all Management Incentive Units held by the Defaulting Member (vested or unvested) for no consideration; and

(D) subject to the provisions of Section 3.7(b), for a period of 30 days after the occurrence of a Payment Default, the Company first right to elect to

purchase all or any portion of the Interests then held by such Defaulting Member (the "*Default Interests*") at a 33% discount to the lesser of (1) such Defaulting Member's cost for the Interests to be purchased and (2) the "fair market value" of the Interests to be purchased (the "*Default Price*"). For purposes of this Section 3.2(d)(ii)(D), "fair market value" is determined by the Board of Managers assuming the Development Agreement has been terminated as a result of a Company default thereunder (whether or not the Development Agreement has actually been so terminated). To the extent the Company does not exercise in full its right to purchase the Default Interests (the portion of the Default Interests for which the Company does not elect to purchase being the "*Remaining Default Interests*"), it shall so notify all Eligible Investors on or prior to the 30th day following the Payment Default (the "*Default Rights Notice*"). Each Eligible Investor shall have 60 days from receipt of the Default Rights Notice to (the "*Default Rights Notice Period*") to elect to purchase up to its pro rata share of such Remaining Default Interests at the Default Price. If any Eligible Investor does not elect to purchase its full pro rata share of the Remaining Default Interests, those Eligible Investors who have elected to purchase their full pro rata share of the Remaining Default Interests and who have notified the Company within the Default Rights Notice Period that they desire to purchase more than their full pro rata share of the Remaining Default Interests may purchase their respective pro rata share of any remaining balance of the Remaining Default Interests. All purchases of Default Interests by the Company and by Eligible Investors must be completed on or before 180 days following the Payment Default. In each case, the phrase "pro rata share" as used in this Section 3.2(d)(ii)(D) shall mean such Eligible Investor's pro rata share based on the Eligible Investor's respective Fully-Funded Percentage Interest.

(iii) In addition to the foregoing, the Company shall have the right to pursue any other remedy existing at law or in equity for the collection of the unpaid amount (and interest thereon) of the Capital Contributions agreed to be made. The Defaulting Member shall be liable for the reasonable costs and expense (including reasonable attorneys' fees and expenses) incurred by the Company or any other Member arising under this Section 3.2(e).

(e) *No Third Party Beneficiaries.* Notwithstanding anything herein to the contrary in this Agreement, any obligation of a Member to make any additional Capital Contributions pursuant to Section 3.2(c) or otherwise in this Agreement shall not create any rights, remedies or claims in favor of or enforceable by any Person who is not a party to this Agreement.

(f) *Certain Bookkeeping*. For purposes of determining each Common Unitholder's IRR as of any date of determination, the Company shall maintain its books and records in a manner that reflects the dates on which each Common Unitholder has made or makes, or is deemed to have made, Capital Contributions to the Company and the amount of each Capital Contribution on each such date.

(g) *Deemed Approval.* Notwithstanding the terms of Section 3.2(b), if the Board of Managers fails to approve any Capital Call recommended by the Managing Member for the

purpose of funding the Company's requirements pursuant to a Commitment Cash Call and such failure to approve and fund such Capital Call would result in a default by the Company under the Development Agreement as determined by the Managing Member in good faith, then such Capital Call shall, unless such Capital Call is expressly rejected in writing by Supermajority Member Approval within five Business Days after delivery of notice by the Company to the Common Unitholders of such failure by the Board of Managers to approve such Capital Call, be deemed approved by the Board of Managers for all purposes to the extent of the amounts required to avoid such a default by the Company under the Development Agreement, and each Member shall be obligated (but only to the extent of such Member's Remaining Capital Commitment) to make its respective additional Capital Contributions as set forth in this Section 3.2 as if the Board of Managers had approved such recommendation by the Managing Member for a Capital Call in the amount required to avoid such default.

3.3 Preemptive Rights.

Prior to a Final Exit Event or an Initial Public Offering, if the Company proposes to issue additional Interests or securities convertible into or exercisable or exchangeable for Interests (other than (a) issuances of Management Incentive Units to Officers or other employees or consultants of the Company, its Subsidiaries or the Management Company (as approved in accordance with the terms of this Agreement) (b) issuances of Interests upon the consummation of Capital Calls or otherwise contemplated by this Agreement, (c) Interests issued by the Company as consideration in an acquisition of any other Person, business or assets (as approved in accordance with the terms of this Agreement), (d) Interests issuable upon the conversion, exercise or exchange of Interests, (e) Interests issued to satisfy any repurchase right or obligation of the Company related to the termination of any employee of the Company, its Subsidiaries or the Management Company or (f) Interests issued pursuant to the Additional Beato Commitment), the Company shall give written notice to the Common Unitholders who are not Defaulting Members setting forth the purchase price, rights and limitations of such additional Interests and the terms and conditions upon which they are proposed to be issued. Thereafter, each Common Unitholder who is not a Defaulting Member and is an accredited investor as defined in the Securities Act and certifies as such to the Company's satisfaction (each, an "*Eligible Investor*"), shall have the preemptive right to acquire up to its pro rata share of such additional Interests. The Eligible Investors may exercise such preemptive rights by purchasing, within 20 Business Days of receiving notice of the proposed issuance from the Company (the "*Preemptive Rights Notice Period*"), up to their respective pro rata share of the additional Interests upon the terms and conditions and for the purchase price set forth in the notice. If any Eligible Investor does not elect to purchase its full pro rata share of the additional Interests, those Eligible Investors who have elected to purchase their full pro rata share of the additional Interests and who have notified the Company within the Preemptive Rights Notice Period that they desire to purchase more than their full pro rata share of the additional Interests may purchase their respective pro rata share of any remaining balance of the additional Interests. After the expiration of the Preemptive Rights Notice Period, the Company shall have the power to sell all of the additional Interests that have not been purchased to one or more third parties, but only upon the terms and conditions and for the purchase price set forth in the notice or upon more economically favorable terms to the Company and the existing Members and provided that, if such sale is not consummated on or before 120 days after the expiration of the Preemptive Rights Notice Period, the Company must comply again with the procedures set forth in this Section 3.3. In each case, the phrase "pro rata

share" as used in this Section 3.3 shall mean such Eligible Investor's pro rata share based on the Eligible Investor's respective Fully-Funded Percentage Interest. Each Member hereby irrevocably waives its preemptive rights under Section 3.3 of the First Amended and Restated Agreement with respect to the Capital Contribution made by Russell and the issuance of any Common Units related thereto.

3.4 Management Incentive Plan.

(a) *Purpose*. As of the Effective Date, the Company and the Members established an incentive compensation plan (the "*Plan*") to provide incentives to Managers, employees and independent contractors of the Company, its Subsidiaries and the Management Company by providing such persons with awards of Management Incentive Units having the rights, preferences, limitations, obligations and liabilities provided thereto in Exhibit B to this Agreement and in the award letters to be delivered by the Company to each Management Incentive Member at or about the time Management Incentive Units are granted thereto (each such award letter, an "*Award Letter*") or in any employment agreement between such Management Incentive Member and the Management Company, pursuant to which such Management Incentive Member provides services to the Management Company in connection with the provision of services by the Management Company to the Company pursuant to the Services Agreement (each, an "*Employment Agreement*"). If the terms of the Plan, any Award Letter or any Employment Agreement conflict in any way with the terms of this Agreement, the terms of this Agreement will govern and if the terms of any Award Letter or any Employment Agreement conflict in any way with the terms of the Plan, the terms of the Plan will govern.

(b) *Authorized Units.* As of the Second Amendment Date, there is authorized a total of 1,000,000 Management Incentive Units to be issued pursuant to the Plan. The Board of Managers may authorize a greater number of Management Incentive Units from time to time. The Management Incentive Units are intended to constitute "profits interests" within the meaning of Revenue Procedures 93-27 and 2001-43, unless the Board of Managers determines otherwise with respect to particular Management Incentive Units.

(c) *Prior Management Incentive Unit Grants.* On the Effective Date, and subject to the provisions of their related Employment Agreements entered into on the Effective Date, the Company granted and issued to certain Members the number of Management Incentive Units specified on Exhibit A-2 to this Agreement. The Deemed Exercise Price of each such Management Incentive Unit was $0.

(d) *Subsequent Management Incentive Unit Grants.* Authorized but unissued or forfeited Management Incentive Units may be awarded under the Plan at any time on or after the Effective Date to such individuals that the Managing Member recommends to the Board of Managers and the Board of Managers approves, in each case, pursuant to Award Letters in such form (which may differ for different individuals) as is approved by the Board of Managers. The entire total of Management Incentive Units reflecting all grants made pursuant to the Plan shall be available to the Board of Managers but shall not be available to other Management Incentive Members.

3.5 Return of Contributions.

No interest shall accrue on any contributions to the capital of the Company, and no Member shall have the right to withdraw or to be repaid any capital contributed by such Member, except as otherwise specifically provided in this Agreement. Loans by a Member to the Company shall not be considered Capital Contributions.

3.6 Member Representations.

(a) Each Member hereby represents and warrants to the Company and to the other Members:

(i) such Member's Interest is acquired for investment purposes only for his or its own account and not with a view to or in connection with any distribution, reoffer, resale or other disposition not in compliance with the Securities Act and applicable state securities laws;

(ii) such Member alone or together with his or its representatives possesses such expertise, knowledge and sophistication in financial and business matters generally, and in the type of transactions in which the Company proposes to engage in particular, that such Member is capable of evaluating the merits and economic risks of acquiring and holding an Interest, and that such Member is able to bear all such economic risks now and in the future;

(iii) such Member has had access to all of the information with respect to his or its Interest that such Member deems necessary to make a complete evaluation thereof;

(iv) such Member's decision to acquire an Interest for investment has been based solely upon the evaluation made by such Member;

(v) such Member is aware that he or it must bear the economic risk of such Member's investment in the Company for an indefinite period of time because Interests have not been registered under the Securities Act or under the securities laws of any State, and therefore, such Interests cannot be sold unless they are subsequently registered under the Securities Act and any applicable state securities laws or an exemption from registration is available;

(vi) such Member is aware that only the Company can take action to register interests in the Company and the Company is under no such obligation and does not propose or intend to attempt to do so other than pursuant to the terms of this Agreement;

(vii) such Member is aware that this Agreement provides restrictions on the ability of a Member to Transfer Interests; and

(viii) such Member is an "accredited investor" within the meaning of Regulation D under the Securities Act.

(b) Clark hereby represents to each of the other Members that the provisions of Section 1.10 are true and correct.

3.7 Non-Voting Interests.

(a) Any Interest in the Company that is (i) held for its own account by a BHC Member or by any affiliates (as defined in 12 U.S.C. Sec. 1841(k)) of a BHC Member that are BHC Members ("*BHC Affiliates*", and, collectively with such BHC Member, the "*BHC Group*"), and (ii) determined in the aggregate to have voting rights with respect to a matter in excess of 4.99% (or such greater percentage as may be permitted under Section 4(c)(6) of the BHCA) of the voting rights of Interests of the Members (such determination to be made (A) at the time of admission of each BHC Member to the Company, (B) at the time of admission of any additional Member to, or withdrawal of any Member from, the Company or (C) at any other time when an adjustment is made to the Members' proportionate Interests or voting rights attributable to such Interests (each, a "*Recalculation Event*")), shall be treated as "*Non-Voting Interests*" except as provided below. In the event that the Interests of a BHC Group are determined in the aggregate to include Non-Voting Interests, such BHC Group may by notice to the Company allocate voting Interests and Non-Voting Interests among themselves in such percentages as they may elect. Upon any Recalculation Event, the Interests in the Company held by a BHC Group shall be recalculated, and only that portion of the aggregate Interest in the Company held by such BHC Group that is determined as of the date of such Recalculation Event to have voting rights in excess of 4.99% with respect to a matter (or such greater percentage as may be permitted under Section 4(c)(6) of the BHCA) of the Interests of the Members, excluding Non-Voting Interests as of such date, shall be a Non-Voting Interest.

(b) Except as provided in this Section 3.7(b), Non-Voting Interests (whether or not subsequently transferred in whole or in part to any other person or entity) shall not be entitled to vote or consent with respect to any matter under this Agreement or the Act, and shall be deemed to have waived any rights to vote or consent with respect to such matters; provided that a BHC Member will be permitted to vote its Non-Voting Interest on any matter that would significantly and adversely affect the rights, preferences or limited liability of such BHC Member, such as modification of the terms of its Interest in relation to the Interests of other Members and other matters as to which non-voting equity are permitted to vote pursuant to 12 C.F.R. Sec. 225.2(q)(2), as in effect from time to time. Except as provided by the immediately preceding sentence, Non-Voting Interests will not be counted (in either the numerator or the denominator of Interests entitled to vote on any matter) as Interests held by any Member for purposes of determining whether any vote or consent required has been approved under this Agreement or given by the requisite percentage of the Members. Except as provided in this Section 3.7(b), Non-Voting Interests will be identical in all respects to all other Common Units.

(c) Notwithstanding the foregoing, a BHC Member may elect not to be governed by this Section 3.7 by giving written notice to the Company stating that, as a result of a change in law or regulation applicable to such BHC Member or pursuant to such BHC Member's reliance on Section 4(k) of the BHCA, such BHC Member is no longer prohibited from acquiring or controlling more than 4.99% of the voting Interests held by the Members (or such greater percentage as may be permitted by Section 4(c)(6) of the BHCA), in which case the amount of

the Interests held by a BHC Member specified in such notice to be subject to this provision shall be voting Interests. Any such election by a BHC Member may be rescinded at any time by written notice to the Company, provided that any such rescission shall be irrevocable.

ARTICLE 4
ALLOCATIONS AND DISTRIBUTIONS.

4.1 Allocation Among Members.

All items of income, gain, deduction and loss shall be allocated among the Members as provided in Exhibit C.

4.2 Regular Distributions.

(a) Available Cash and other applicable property shall be distributed to the Members solely at such times and in such amounts as the Board of Managers shall determine. The cumulative amount of Available Cash and, if applicable, other property declared by the Board of Managers to be available for distribution under this Section 4.2(a) shall first be allocated to, but not distributed to, each Common Unitholder (including Defaulting Members) on a pre-tax basis in accordance with each Common Unitholder's Capital Contribution Ratio (the amount allocated to, but not distributed to, each Common Unitholder in accordance with this sentence is referred to as such Common Unitholder's "*Allocable Share*"). Each Common Unitholder's Allocable Share shall then be distributed according to the following tiered (each, a "*Tier*") distribution waterfall (as further illustrated in Exhibit D assuming all Capital Commitments as of the Effective Date are fully funded), subject, however, to the terms of Section 3.2(d) and Section 4.2(b).

(i) **Tier 1**. First, to such Common Unitholder until such Common Unitholder has received distributions pursuant to this Section 4.2(a)(i) (including distributions made by reason of Section 4.2(b)(i)) sufficient to cause its IRR to be ten percent (10%) (the "*First Threshold*").

(ii) **Tier 2**. Second, ninety percent (90%) to such Common Unitholder and ten percent (10%) to the Management Incentive Members in proportion to their MIU Percentages until (A) the IRR of such Common Unitholder is greater than twenty percent (20%) and (B) such Common Unitholder has received Total Distributions with respect to the Common Units held by such Common Unitholder equal to 2.0 times the amount of its aggregate Capital Contributions (the "*Second Threshold*").

(iii) **Tier 3**. Third, eighty percent (80%) to such Common Unitholder and twenty percent (20%) to the Management Incentive Members in proportion to their MIU Percentages until (A) the IRR of such Common Unitholder is greater than twenty percent (20%) and (B) such Common Unitholder has received Total Distributions with respect to the Common Units held by such Common Unitholder equal to 3.0 times the amount of its aggregate Capital Contributions (the "*Third Threshold*").

(iv) **Tier 4.** Fourth, seventy-seven percent (77%) to such Common Unitholder and twenty-three percent (23%) to the Management Incentive Members in proportion to

their MIU Percentages until (A) the IRR of such Common Unitholder is greater than twenty-five percent (25%) and (B) such Common Unitholder has received Total Distributions with respect to the Common Units held by such Common Unitholder equal to 4.0 times the amount of its aggregate Capital Contributions (the "*Fourth Threshold*").

(v) **Tier 5.** Fifth, seventy-five percent (75%) to such Common Unitholder and twenty-five percent (25%) to the Management Incentive Members in proportion to their MIU Percentages.

(vi) **Deemed Exercise Price.** Notwithstanding the provisions of Sections 4.2(a)(ii), (iii), (iv) and (v) above, any amount that would otherwise be distributed to the holder of a Management Incentive Unit in respect of which there is a non-zero Deemed Exercise Price shall be withheld therefrom until the amount that is so withheld in respect of that Management Incentive Unit is equal to the Deemed Exercise Price of that Management Incentive Unit. Any amount so withheld will be treated as part of the Unallocated MIU Percentage and distributed as provided in Section 4.2(a)(vii); provided that a Management Incentive Unit with a non-zero Deemed Exercise Price shall not be entitled to distributions of amounts withheld pursuant to this Section 4.2(a)(vi) with respect to (A) such Management Incentive Unit or (B) the portion of the Deemed Exercise Price of any other Management Incentive Unit that is less than or equal to the Deemed Exercise Price of such Management Incentive Unit.

(vii) **Unallocated MIU Percentage**. Distributions that would otherwise be made to the Management Incentive Members shall be withheld until the amount that has so been withheld is equal to the aggregate of all amounts that have theretofore been applied to redeem or repurchase Management Incentive Units ("*Withheld Amount*"). Such Withheld Amount will be distributed to the Common Unitholders in accordance with their Capital Contribution Ratios. After the Common Unitholders have in the aggregate received the Withheld Amount, all remaining distributions to the Unallocated MIU Percentage shall be made to the Management Incentive Members in proportion to their MIU Percentages.

(b) **Additional Distribution Rules**. The distribution rules in this Section 4.2(b) shall be applied notwithstanding anything to the contrary in Section 4.2(a). The following rules shall be applied to each Common Unitholder and to the extent applicable, the Management Incentive Members, separately with respect to each such Common Unitholder's Allocable Share:

(i) **True-Up Distributions**. Because such Common Unitholder may have achieved the First Threshold, the Second Threshold, the Third Threshold or the Fourth Threshold as of one date but may not have achieved such First Threshold, Second Threshold, Third Threshold or the Fourth Threshold as of a later date, then prior to making each distribution under Section 4.2(a) of any portion of an Allocable Share in respect of a Common Unitholder, the Company shall first distribute to such Common Unitholder an amount under Section 4.2(a)(i), Section 4.2(a)(ii), Section 4.2(a)(iii) or Section 4.2(a)(iv) sufficient to achieve for such Common Unitholder the conditions that are stated in such Section 4.2(a)(i), Section 4.2(a)(ii), Section 4.2(a)(iii) or Section

4.2(a)(iv), as the case may be, taking into account all Capital Contributions made on or prior to the date of the distribution. For purposes of clarification, amounts that are so distributed to a Common Unitholder shall count in determining whether such Common Unitholder has met the conditions that are stated in such Section 4.2(a)(i), Section 4.2(a)(ii), Section 4.2(a)(iii) or Section 4.2(a)(iv).

(ii) **Retained MIU Amount**. Notwithstanding Section 4.2(a) and except as provided below, if Remaining Capital Commitments are outstanding prior to any distribution of proceeds that is being made prior to the final liquidation of the Company (such a distribution, an "*Interim Distribution*"), then, to the extent that (A) the amount of proceeds that would be distributable to the holder of a Management Incentive Unit (whether vested or unvested) pursuant to this Agreement (other than pursuant to Section 4.3) in such Interim Distribution (such an amount described in this clause (A), a "*Current MIU Distribution Amount*") exceeds (B) the amount of proceeds that would be distributable to the holder of such Management Incentive Unit (whether vested or unvested) pursuant to this Agreement (other than pursuant to Section 4.3) in such Interim Distribution assuming (x) all Remaining Capital Commitments were fully funded to the Company immediately prior to such Interim Distribution and (y) no other proceeds are or will be available for distribution following such Interim Distribution (such an amount described in this clause (B), an "*Estimated MIU Distribution Amount*"), the excess of such Current MIU Distribution Amount over the Estimated MIU Distribution Amount shall be retained by the Company rather than distributed to such holder of a Management Incentive Unit in such Interim Distribution (such retained amount, a "*Retained Amount*") and the remainder of such Current MIU Distribution Amount shall be distributed to such holder of a Management Incentive Unit in such Interim Distribution. Following such Interim Distribution, the Company shall retain all outstanding Retained Amounts until the earlier of (1) the next Interim Distribution, at which time all outstanding Retained Amounts shall be available for distribution to the holders of Common Units and Management Incentive Units, along with the other proceeds available in such next Interim Distribution, but subject to being retained again by the Company pursuant to the terms of this Section 4.2(b)(ii) and (2) the final liquidation of the Company, at which time all outstanding Retained Amounts shall be available for distribution to the holders of Common Units and Management Incentive Units, along with any other proceeds available for distribution in such liquidation. For the avoidance of doubt, amounts previously distributed to Common Unitholders shall be taken into account in each determination of Retained Amount.

(iii) **Unvested Management Incentive Units**. Except as provided in Section 4.3, no distributions shall be made to a Management Incentive Member with respect to unvested Management Incentive Units. Subject to Section 4.2(b)(ii), the Company shall pay to such Management Incentive Member an amount equal to the amount of the distribution that the Management Incentive Member would have received but for the preceding sentence when such Management Incentive Units vest.

(c) **Effect of Transfers of Interests**. In the event of a transfer of all or part of an Interest permitted under Section 3.7 or Article 9 hereof, the transferee will succeed to the attributes of the predecessor owner of the transferred Interest for purposes of applying this

Article 4 and Article 8 to the transferred Interest, except as otherwise provided in any amendment to this Agreement admitting the transferee as a Member. If the transferee already owns an Interest, the determinations under Section 4.2 shall be made separately with respect to the transferred Interest and the Interest(s) already owned.

4.3 Tax Distributions.

Notwithstanding Section 4.2 and the other provisions hereof, the Company shall within 30 days after the end of each Fiscal Quarter distribute to each Member (a "*Tax Distribution*") who requests, in such Member's sole discretion, distributions pursuant to this Section 4.3 the positive amount equal to such Member's share of the Maximum Quarterly Company Tax Distribution; provided that, notwithstanding anything to the contrary in this Section 4.3, the Company shall not make a distribution pursuant to this Section 4.3 to the extent such distribution exceeds Available Cash or if the distribution would cause a default or breach by the Company under any credit facility to which the Company is a party. For this purpose, a Member's share of the Maximum Quarterly Company Tax Distribution shall be reasonably determined by the Board of Managers. Any amount that is distributed pursuant to this Section 4.3 shall be treated for all purposes of Section 4.2 as having been distributed pursuant thereto and shall be treated as having been distributed out of the Allocable Shares of the Common Unitholders that the Board of Managers reasonably determines.

4.4 Withholding.

(a) The Company is hereby authorized to withhold from any distribution to any Member and to pay over to any federal, state, local or foreign government any amounts required to be so withheld pursuant to federal, state, local or foreign law. All amounts so withheld pursuant to federal, state, local or foreign tax laws shall be treated as amounts actually distributed to the affected Members for all purposes under this Agreement.

(b) To the extent such amount has not been withheld from a distribution pursuant to Section 4.4(a), each Member shall promptly contribute to the Company cash in the amount, if any, that the Company is required to pay over to the Internal Revenue Service pursuant to Section 1446 of the Code in respect of that Member or to pay over to any other governmental entity pursuant to any comparable provision of applicable Law and in that event the payment to the Internal Revenue Service or other governmental entity shall not be treated as a distribution and the payment to the Company shall not be treated as a Capital Contribution.

(c) The Members shall furnish to the Company from time to time all such information as is required by applicable Law or is otherwise reasonably requested by the Company (including certificates in the form prescribed by the Code and applicable Treasury Regulations or applicable state, local, or foreign law) to permit the Company to ascertain whether and in what amount any tax withholding is required. Any Member whose status changes (including through a change in the tax classification of such Member or a related party) in a manner that causes withholding to apply (whether under Section 1446 of the Code or otherwise) shall promptly notify the Company of such change.

ARTICLE 5
MANAGEMENT OF THE COMPANY

5.1 Managers.

The powers of the Company shall be exercised by or under the authority of, and the business, property and affairs of the Company shall be managed under the direction of, the Board of Managers.

5.2 Number and Designation of Managers.

(a) *Initial Number.* There shall be seven Managers on the Board of Managers; provided, the size of the Board shall increase (with such increase to be filled by the Board of Managers) or decrease from time to time as determined by the Board of Managers, subject to Supermajority Member Approval.

(b) *Contaro Managers.* Contaro shall have the right to designate two Managers. The Managers designated by Contaro shall collectively be referred to as the "*Contaro Managers*". As of the date of this Agreement, Joseph J. Romano and John B. Juneau serve as the Contaro Managers.

(c) *Sageview Managers.* The Sageview Parties shall have the right to designate two Managers. The Managers designated by the Sageview Parties shall collectively be referred to as the "*Sageview Managers*". As of the date of this Agreement, Edward A. Gilhuly and Andrew J. Campelli serve as the Sageview Managers.

(d) *Jefferies Managers.* The Jefferies Parties shall have the right to designate two Managers. The Managers designated by the Jefferies Parties shall collectively be referred to as the "Jefferies Managers". As of the date of this Agreement, James Luikart and George Hutchinson serve as the Jefferies Managers.

(e) *Management Member.* One Manager shall be the Managing Member (the "*Management Manager*").

(f) *Additional Managers.* The Board of Managers shall have the right to designate any remaining Manager(s).

(g) *Board Observers*. Each of Wells Fargo and Union Bank shall be entitled to designate one observer (each a "*Board Observer*") at all meetings, including telephonic meetings, of the Board of Managers and all committees that the Board of Managers may establish. Each Board Observer shall have no voting rights with respect to any action brought before the Board of Managers. Notwithstanding the first sentence of this Section 5.2(g), Board Observers shall not be entitled to attend any portion of a meeting of the Board of Manager that (i) would constitute, or be deemed to constitute, a waiver of the attorney-client privilege or (ii) includes a discussion of an agreement or transaction between the Company and the Board Observer, the Member that designated the Board Observer or any of their respective Affiliates. Board Observers shall be entitled to receive all materials provided to Managers in preparation for meetings unless the provision of such materials would constitute, or be deemed to

constitute, a waiver of the attorney-client privilege. Board Observers shall receive notice of all actions taken by the Board of Managers, whether such action is taken at a meeting or by written consent.

5.3 Voting and Action.

(a) *Generally.* Except as expressly otherwise provided in this Agreement, approval by the Board of Managers of any action, including those enumerated in Section 5.11, at a meeting at which a quorum is present shall require the affirmative vote in favor of such action of a majority of the voting power of the Managers. For the avoidance of doubt, references in this Agreement to a majority of disinterested Managers shall mean a majority in voting power of disinterested Managers.

(b) *Voting Power.* Each Manager has one vote.

(c) *Proxies.* Subject to the provisions of this Agreement and applicable Law regarding notice of meetings and the granting of proxies, persons serving on the Board of Managers (i) unless otherwise restricted by the Certificate or this Agreement, may participate in and hold a meeting of the Board of Managers by using conference telephone, electronic transmission, or similar communications equipment by means of which all persons participating in the meeting can hear each other and (ii) may grant a proxy to another Manager or delegate its right to act to another Manager which proxy or delegation shall be effective as the attendance or action at the meeting of the Manager giving such proxy or delegation. Participation in a meeting pursuant to this Section 5.3(c) shall constitute presence in person at such meeting, except when a person participates in the meeting for the express purpose of objecting to the transaction of any business on the ground that the meeting was not lawfully called or convened.

(d) *Absent Members.* Without limiting Section 5.3(c) regarding the granting of proxies, if any Contaro Manager, Sageview Manager or Jefferies Manager is absent from a meeting, the Contaro Manager, Sageview Manager or Jefferies Manager, respectively, who is present at such meeting shall be entitled to cast the votes of the Contaro Managers, the Sageview Managers or Jefferies Managers, respectively, as such present Manager deems fit in his sole discretion.

(e) *Written Consents.* Any action required or permitted to be taken at any meeting of the Board of Managers may be taken without a meeting, without prior notice and without a vote if consents in writing, setting forth the action so taken, are signed by all Managers.

(f) *Additional Actions.* Any action or decision approved in accordance with this Agreement may be carried out by the Managing Member or other Officer on behalf of the Company.

5.4 Meetings of Managers.

(a) *Regular Meetings.* For the first 12 months following the Effective Date, regular meetings shall be held every two months on such dates, at such places and at such times as shall be determined by the Board of Managers. Regular meetings of the Board of Managers

subsequent to the first anniversary of the Effective Date shall be held at least quarterly on such dates, at such places and at such times as shall be determined by the Board of Managers. Notice of the establishment of such regular meeting schedule, and of any amendments thereto, shall be given to any Manager (or Board Observer) who was not present at the meeting at which such schedule or amendment was adopted or who did not execute the written consent in which such schedule or amendment was adopted.

(b) *Special Meetings.* Special meetings of the Board of Managers may be called by any Manager. Any such meeting shall be held on such date, at such place and at such time as the Manager calling such meeting shall specify in the notice of the meeting which shall be delivered to each other Manager (and each Board Observer) at least 72 hours (unless waived by the unanimous agreement of the Board of Managers) prior to such meeting. The purpose of and business to be transacted at such special meeting must be specified in the notice (or waiver of notice) of such meeting.

(c) *Quorum*. Unless otherwise expressly provided in this Agreement, the presence (or representation if permitted by Delaware law) of a majority in voting power of the Managers shall be necessary and sufficient to constitute a quorum for the transaction of business at any meeting of the Board of Managers. If a quorum shall not be present at any meeting of the Board of Managers, the Managers present at such meeting may adjourn the meeting from time to time, without notice other than announcement at the meeting, until a quorum shall be present. At any such adjourned meeting at which a quorum is present, any business may be transacted that might have been transacted at the meeting as originally convened.

(d) *Manager Expenses and Compensation.* Managers shall be entitled to prompt reimbursement of all reasonable out-of-pocket expenses incurred in the course of the performance of their duties, but shall not otherwise be entitled to compensation for their services in their capacity as Managers.

5.5 Resignation and Removal.

Any Manager may resign at any time. Any Manager may be removed at any time, with or without cause, solely by the Member or Members that designated such Manager.

5.6 Vacancies.

In the event of the death, resignation or removal of a Manager designated by Contaro, the Sageview Parties or the Jefferies Parties, the resulting vacancy shall be filled by Contaro, the Sageview Parties or the Jefferies Parties, respectively. In the event of the death, resignation or removal of any Manager designated by the Board of Managers, the resulting vacancy shall be filled by the Board of Managers.

5.7 Officers and Employees.

The CEO may hire and appoint Officers and employees of the Company and its Subsidiaries for positions provided for in an Approved Budget, and may designate the authority, responsibilities, ranking and titles of such Officers and employees and may remove or discharge such individuals from such position; provided, that all Officer appointments shall be subject to the approval of the

Board of Managers and provided, further, that the Board of Managers must appoint the President of the Company and the CEO.

5.8 Compensation.

Subject to an Approved Budget and any Employment Agreement approved by the Board of Managers, the salaries and other compensation of the Officers (other than the President and the CEO) or the officers of the Company's Subsidiaries shall be set or adjusted from time to time as recommended by the CEO (or the Managing Member if no CEO is then in office) and as approved by the Board of Managers. Subject to any Employment Agreement approved by the Board of Managers, the salaries and other compensation of the President and the CEO of the Company or its Subsidiaries shall be set or adjusted from time to time by the Board of Managers. Subject to an Approved Budget, the salaries and other compensation of non-officer employees of the Company or its Subsidiaries shall be as reasonably set and adjusted by the CEO (or the Managing Member if no CEO is then in office).

5.9 Powers of Managers.

Subject to the limitations set forth in Section 5.11 and all other limitations in this Agreement, the Board of Managers shall have the power and authority to manage and control the Company and to do all things they deem to be necessary, convenient or advisable in connection with the management of the Company.

5.10 Authority of Managing Member.

Subject to Section 5.11 or until such authority is revoked by the Board of Managers, the Managing Member is hereby delegated the day-to-day authority to manage the Company and make decisions on behalf of the Company with respect to the ordinary conduct of the business of the Company, as described in Section 1.3, including the authority to acquire and dispose of oil and natural gas properties and other assets, to enter into contracts, to expend funds, to borrow money, to pursue, defend and settle claims, to contract for the employment and services of employees and independent contractors and to take such other actions as may be incidental to any of the foregoing.

5.11 Action Requiring Special Approvals.

(a) Notwithstanding any other provision of this Agreement to the contrary, neither the Managing Member nor any other Officer or employee shall approve, cause, permit or take any of the following actions for the Company or any of its Subsidiaries without the approval of the Board of Managers, unless such actions were previously and expressly approved by the Board of Managers in connection with, or as part of, an Approved Budget:

(i) Adopt, amend or permit an Approved Budget or any other budget for the Company or its Subsidiaries except as provided in Section 7.4;

(ii) approve any Capital Calls, subject to the deemed approval of any Capital Calls as set forth in Section 3.2(i);

(iii) obligate, cause or permit the Company or any of its Subsidiaries to make or receive any payment or expenditure or series of related payments or expenditures in excess of an aggregate of $250,000;

(iv) obligate, cause or permit the Company or any of its Subsidiaries to sell, lease or otherwise transfer assets of the Company or any of its Subsidiaries in any single transaction or series of related transactions having a value in excess of $250,000;

(v) obligate, cause or permit the Company or any of its Subsidiaries to enter into, amend or modify any credit facility or otherwise incur, assume or become liable for any indebtedness for borrowed money that, on an aggregate basis, exceeds the amount provided in an Approved Budget for a credit facility or obligate or cause the Company or any of its Subsidiaries to guarantee the payment of money or performance of any obligation by any other Person that would have the same or similar effect;

(vi) obligate, cause or permit the Company or any of its Subsidiaries to make any loans, advances or capital contributions to, or investments in, any other Person other than (A) in the ordinary course to any wholly-owned Subsidiary of the Company or (B) payroll advances to employees in the ordinary course of business consistent with past practice and not to exceed $10,000 in the aggregate for any employee;

(vii) obligate, cause or permit the Company or any of its Subsidiaries to purchase, forgive, redeem, cancel, prepay or other completely or partially discharge in advance of a scheduled payment or mandatory redemption date of any indebtedness, loan, advance, capital contribution or investment obligation in any transaction or series of related transactions;

(viii) obligate, cause or permit the Company or any of its Subsidiaries to enter into or modify any commodity or interest rate hedging transaction;

(ix) obligate or cause the Company to amend, modify or replace the Services Agreement;

(x) obligate or cause the Company to issue Management Incentive Units to any Manager or any other Person;

(xi) obligate, cause or permit the Company or any of its Subsidiaries to repurchase from Management any equity interests or any options or rights to acquire any such equity interests (except pursuant to the equity repurchase provisions set forth in this Agreement or of any other agreements previously approved by the Board of Managers);

(xii) approve or cause any Final Exit Event (other than a Drag-Along Transaction) involving solely cash or Marketable Securities as consideration or an Initial Public Offering, in each case after the third anniversary of the Effective Date;

(xiii) approve, cause or permit the Company or any of its Subsidiaries to establish a Subsidiary;

(xiv) obligate, cause or permit the Company or any of its Subsidiaries to settle or initiate any litigation or proceeding for an amount exceeding $100,000;

(xv) hire or terminate the CEO or any other executive officer of the Company or any Subsidiary of the Company conducting all or substantially all of the business of the Company and its Subsidiaries;

(xvi) obligate, cause or permit the Company or any of its Subsidiaries to enter into or amend any material term of (A) any Employment Agreement or arrangement with any senior employee, (B) the compensation or benefits of any senior employee, (C) any unit option, employee unit purchase or similar equity-based plans, (D) any benefit, severance or other similar plan or (E) any annual bonus plan or any management equity plan;

(xvii) obligate, cause or permit the Company or any of its Subsidiaries to enter into or amend any material term of a contract providing for the indemnification or holding harmless of any officer, director, manager, equityholder or employee of the Company or any of its Subsidiaries;

(xviii) obligate, cause or permit the Company or any of its Subsidiaries to enter into or amend any agreement that (A) expressly limits the ability of the Company or any of its Affiliates to compete in or conduct any line of business or compete with any Person or in any geographic area or during any period of time or (B) contains exclusivity, "most favored nation" or similar obligations or restrictions that are binding on the Company or any of its Affiliates;

(xix) obligate or cause the Company to select, approve or terminate the independent auditing firm engaged by the Company;

(xx) obligate or cause the Company to select, approve or terminate the independent petroleum engineering firm engaged by the Company;

(xxi) establish or amend any material tax policies or make or change any tax elections of the Company or any of its Subsidiaries;

(xxii) obligate, cause or permit the Company or any of its Subsidiaries to make any public announcements regarding the Company or any of its Affiliates;

(xxiii) cause the Company to adopt any insurance risk management policies or insurance programs for the Company;

(xxiv) cause the Company to adopt health and safety guidelines; and

(xxv) approve any change in the Company's Fiscal Year.

(b) Notwithstanding any other provision of this Agreement to the contrary, neither the Managing Member nor any other Officer or employee shall approve, permit or take any of the following actions for the Company or any of its Subsidiaries without the approval of the

Board of Managers and Supermajority Member Approval, unless such actions were previously and expressly approved by the Board of Managers and Supermajority Member Approval in connection with, or as part of, an Approved Budget:

(i) increase the size, compensation or reimbursement policy of the Board of Managers;

(ii) obligate, cause or permit the Company or any of its Subsidiaries to make any material change in operating strategy or in the lines of business of the Company and its Subsidiaries taken as a whole;

(iii) obligate or cause the Company to make any distributions to the Members (other than Tax Distributions);

(iv) obligate, cause or permit the Company or any of its Subsidiaries to acquire (A) assets or properties in an amount exceeding $250,000 or (B) any equity interests in any Persons;

(v) obligate, cause or permit the Company or any of its Subsidiaries to enter into any joint venture or similar business arrangement;

(vi) obligate, cause or permit the Company or any of its Subsidiaries to make expenditures unrelated to the Development Agreement;

(vii) obligate, cause or permit the Company or any of its Subsidiaries to farm-out acreage or carve out of any Company or Subsidiary assets, profits interests, overriding royalty interests or other similar interests on properties;

(viii) obligate or cause the Company to repurchase any Interest from any Member other than Management (except under repurchase provisions of agreements previously approved by the Board of Managers and by Supermajority Member Approval);

(ix) subject to Section 5.12, obligate, cause or permit the Company or any of its Subsidiaries to enter into, amend or terminate agreements between the Company or any of its Subsidiaries, on the one hand, and any Affiliate thereof (other than the Company or any of its Subsidiaries) on the other hand (it being understood that approval of the Board of Managers for purposes of this clause (ix) shall require the approval of a majority of the votes held by the disinterested Managers);

(x) obligate, cause or permit the Company or any of its Subsidiaries to enter into, amend or terminate any material contract (including without limitation the Development Agreement);

(xi) obligate, cause or permit the Company or any of its Subsidiaries to approve any Refrac Pilot Project (as defined in the Development Agreement) or any expenditures related thereto;

(xii) approve or cause (A) any Final Exit Event (other than a Drag-Along Transaction) or Initial Public Offering prior to the third anniversary of the Effective Date or (B) any Final Exit Event (including a Drag-Along Transaction) from and after the third anniversary of the Effective Date that includes any consideration other than cash or Marketable Securities;

(xiii) approve, cause or permit any consolidation, merger or other business combination involving any of the Company's Subsidiaries or any conversion of any of the Company's Subsidiaries to another type or form of business entity;

(xiv) obligate or cause the Company to issue any additional Interests or securities convertible into Interests (other than up to 1,000,000 Management Incentive Units as provided for in this Agreement) or obligate, cause or permit any Subsidiary to issue any securities to any Person;

(xv) obligate or cause the Company to settle or initiate any litigation or proceeding for an amount exceeding $250,000;

(xvi) obligate or cause the Company to wind up, dissolve or liquidate;

(xvii) obligate or cause the Company to be recapitalized or similarly reorganized;

(xviii) cause the Company to commence a voluntary proceeding in bankruptcy; and

(xix) amend this Agreement or the Certificate (except as otherwise set forth in Section 11.5).

5.12 Contracts with Affiliates.

The Company and its Subsidiaries may enter into contracts and agreements with the Company's Members and/or any of its Affiliates for the rendering of services on arm's length terms that are no less favorable to the Company and its Subsidiaries than those available from unrelated third parties if such transaction is approved by a majority of the votes held by the disinterested Managers; provided that, if any such transaction involves aggregate consideration with a fair market value in excess of $25,000, such transaction must also be approved by Supermajority Member Approval pursuant to Section 5.11(b)(ix). No such contract or agreement shall be void or voidable solely for such reason and no Person having an interest in any such transaction shall have any liability to the Company or any Member solely by virtue of such relationship or conflict if the material facts as to the relationship and transaction are disclosed or are known to the Members and, if required, the transaction is approved by a majority of the votes held by the disinterested Managers pursuant to this Section 5.12 and pursuant to Section 5.11(b)(ix). Agreements relating to the provision of services as set forth in this Agreement shall be deemed approved for all purposes hereunder.

5.13 Insurance.

The Company shall acquire and maintain insurance covering such risks and in such amounts as the Board of Managers shall from time to time determine to be necessary or appropriate; provided that the Company shall maintain directors and officers liability insurance having policy limits of at least $5 million as long as such coverage is available on such terms (including premiums) as the Board of Managers determines are reasonable.

5.14 Tax Elections.

(a) The Company shall make the following elections for tax purposes on the appropriate returns:

(i) to the extent permitted by Law, to adopt the Fiscal Year as the Company's taxable year;

(ii) to the extent permitted by Law, to adopt the accrual method of accounting and to keep the Company's books and records on such method;

(iii) if a distribution of the Company's property as described in section 734 of the Code occurs or upon a Transfer of an Interest as described in section 743 of the Code, on request by notice from any Member, to elect, pursuant to section 754 of the Code, to adjust the basis of the Company's properties;

(iv) to elect to deduct and amortize the organizational expenses of the Company as permitted by section 709(b) of the Code; and

(v) any other election the Board of Managers deems appropriate and in the best interests of the Members.

(b) To the extent that the classification of the Company for federal income tax purposes does not govern the state and local tax classification of the Company, the Board of Managers shall take such action as may be permitted or required under any state and/or local law applicable to the Company to cause the Company to be taxable as, and in a manner consistent with, a partnership (or the functional equivalent thereof under applicable Law) for the state and/or local income tax purposes. In addition, neither the Company nor any Member may make an election for the Company to be excluded from the application of the provisions of subchapter K of chapter 1 of subtitle A of the Code or any similar provisions of applicable state law and no provision of this Agreement shall be construed to sanction or approve such an election.

(c) The Company may follow the proposed Treasury Regulations that were issued on May 24, 2005 regarding the issuance of partnership equity for services (including Prop. Treas. Reg. §§1.83-3, 1.83-6, 1.704-1, 1.706-3, 1.721-1 and 1.761-1), as such regulations may be subsequently amended, upon the issuance of Interests issued for services rendered or to be rendered to or for the benefit of the Company (the "*Service Interests*") until final Treasury Regulations regarding these matters are issued if the Board of Managers determines to do so. The Company may use a safe harbor implementing the concepts articulated in Internal Revenue Service Notice 2005-43, IRB 2005-24, under which the fair market value of the Service Interest received by any Member is treated as equal to the liquidation value of such

Service Interest (which value is equal to the total amount that would be distributed under Section 8.2 with respect to such Service Interest in a hypothetical liquidation occurring immediately after the issuance of such Service Interest and assuming for purposes of such hypothetical liquidation that all assets of the Company are sold for their fair market values). If the provisions of the proposed Treasury Regulations and the proposed Revenue Procedure described in IRS Notice 2005-43, or provisions similar thereto, are adopted as final (or temporary) rules, the Board of Managers is authorized to make such amendments to this Agreement (including provision for any safe harbor election authorized by such rules) as the Board of Managers may determine to be necessary or advisable.

5.15 Tax Returns.

The Company shall prepare and file or cause to be prepared and filed all federal, state and local income and other tax returns that the Company is required to file; provided that all tax returns must be approved by the Investor Parties before filing; provided further that, the Investor Parties shall notify the Company of approval or non-approval of such tax returns within 10 Business Days of a request for approval of such tax returns shall be deemed not approved. Within 75 days after the end of each Fiscal Year, the Company shall send or deliver, or shall cause to be sent or delivered, to each Person who was a Member at any time during such year such tax information as shall be reasonably required for the preparation by such Person of his federal income tax return and state and other tax returns, including the Member's tentative allowable oil and gas depletion (computed using both cost and percentage depletion methods without regard to any limitation that theoretically could apply to any Member).

5.16 Tax Matters Partner.

The "tax matters partner" of the Company as described in section 6231(a)(7) of the Code shall be Beato or such other Member designated by the Board of Managers. Any Member who is designated the tax matters partner shall take such action as may be necessary to cause each other Member to become a "*notice partner*" within the meaning of section 6223 of the Code. The tax matters partner shall inform each other Member of all significant matters that may come to its attention in its capacity as tax matters partner by giving notice thereof on or before the fifth Business Day after becoming aware thereof and, within that time, shall forward to each other Member copies of all significant written communications it may receive in that capacity. Any Member who is designated as tax matters partner may not take any action contemplated by sections 6222 through 6232 of the Code without the consent of Members whose aggregate Capital Contribution Ratios exceed 51%, and may not in any case take any action left to the determination of an individual Member under sections 6222 through 6232 of the Code.

5.17 Classification.

The Company intends to be classified as a partnership for federal income tax purposes under Treas. Reg. §301.7701-3(c). Neither the Company nor any Member may make an election under Treas. Reg. §301.7701-3 to treat the Company as an association taxable as a corporation.

5.18 Payments and Fees.

Promptly after being presented with an invoice, the Company shall pay or reimburse to the Investor Parties and Management, as a Company expense, all reasonable expenses incurred by them in connection with the negotiation of this Agreement, including attorneys' fees and other professional expenses.

5.19 Subsidiary Governance.

The Company and each Member acknowledge that the Company may, subject to Section 5.11(a)(xiii), from time to time form or acquire Subsidiaries. If such a Subsidiary is a limited liability company, it is the intent of the Members that such limited liability company be sole member-managed so that the Board of Managers of the Company can direct the business and affairs of, and make decisions for, such Subsidiary. If, however, such a Subsidiary is a partnership, it is the intent of the Members that such partnership be managed so that the Board of Managers of the Company can direct the business and affairs of, and make decisions for, such Subsidiary either (a) through the Company so that it shall serve as general partner of such partnership or (b) through another Subsidiary that shall serve as general partner of such partnership. Finally, if such a Subsidiary is a corporation or other type of business entity or is a manager-managed limited liability company, the Company shall take such actions as are necessary to ensure that the governance of each Subsidiary shall parallel the governance of the Board of Managers.

ARTICLE 6
RIGHTS OF MEMBERS

6.1 Rights of Members.

Subject to Section 6.4 and Section 6.5, each of the Members shall have the right to exercise all rights of a Member under the Act (except to the extent otherwise specifically provided herein).

6.2 Liability to Third Parties.

No Member shall be liable for the debts, obligations or liabilities of the Company, including under a judgment decree or order of a court.

6.3 Action by Members.

Except as expressly otherwise provided in this Agreement, all actions and decisions of the Members required hereunder shall require approval of Members whose aggregate Fully Funded Percentage Interests (excluding Non-Voting Interests) total at least 51%. The Members may make any decision or take any action at a meeting, by conference telephone call, by written consent, by oral agreement or by any other method they elect; provided that, at the request of any Member a decision or action of the Members must be made or taken by written consent signed by Members holding the Fully Funded Percentage Interests required to approve such decision or action.

6.4 Area of Mutual Interest

(a) *Restricted Businesses.* Except as permitted by Section 6.4(b), Wells Fargo Energy Capital, Inc. and each of the Members (other than Wells Fargo) shall not, and each of the Members (other than Union Bank and Wells Fargo) shall cause its Affiliates not to, engage directly or indirectly in, whether by acquisition, construction, investment in debt or equity securities of any Person or otherwise, any business having assets or operations located in the "Jonah Field" natural gas field in the Green River Basin in Sublette County, Wyoming as more specifically described on Exhibit G (the "*Restricted Businesses*").

(b) *Permitted Exceptions.* Notwithstanding any provision of this Agreement to the contrary, and subject to the terms of any applicable non-competition agreements between the Company and such Member, any Member may engage in the following activities under the following circumstances:

(i) the purchase and ownership of up to 10.0% of any class of securities of any entity engaged in any Restricted Business, provided that such Member does not exercise Control over such entity;

(ii) the acquisition of, construction of or investment in any Restricted Business or any asset or group of related assets used in any Restricted Business by such Member after the Effective Date (the "Subject Assets") if, in the case of an acquisition, the fair market value of the Subject Assets, or, in the case of an investment, the amount of the investment, or in the case of construction, the estimated construction cost of the Subject Assets, is less than $5 million at the time of such acquisition, investment or construction, as the case may be;

(iii) the acquisition of, construction of or investment in any Subject Assets involving a fair market value, investment or construction cost, as the case may be, greater than that permitted by Section 6.4(b)(i) or Section 6.4(b)(ii); provided the Company has been offered the opportunity to acquire, construct or invest in such Subject Assets in accordance with Section 6.4(c) and the Board of Managers (with the concurrence of a majority of the votes held by the disinterested Managers) has elected not to purchase such Subject Assets pursuant to the provisions of Section 6.4(c);

(iv) any Restricted Business acquired by such Member after the Effective Date with the approval of a majority of the votes held by the disinterested Managers; and

(v) Clark's ownership interest in Odyssey Exploration, Inc. ("*Odyssey*") and the other interests listed on Exhibit H (together with Odyssey, the "*Clark Interests*" and the activities of the Clark Interests as of the Effective Date shall not be deemed to be in competition with the Company; provided that Clark's ownership interest in, or Control over, the Clark Interests as of the Effective Date does not increase thereafter.

(c) *Procedures.*

(i) In the event that a Member becomes aware of an opportunity to acquire, construct or invest in Subject Assets, then, subject to Section 6.4(c)(ii), as soon as practicable and in no event later than 10 days thereafter, such Member shall notify the Board of Managers in writing of such opportunity and deliver to the Board of Managers

all information in the possession of such Member relating to the Subject Assets and such opportunity. As soon as practicable, but in any event within 30 days after receipt of such notification and information, the Board of Managers shall notify such Member in writing that either (A) the Board of Managers has elected (with the concurrence of a majority of the votes held by the disinterested Managers) not to cause the Company or its Subsidiaries to pursue the opportunity to acquire, construct or invest in the Subject Assets (in which case such Member may acquire, construct or invest in such Subject Assets without any further obligation to offer such opportunity to the Company), or (B) the Board of Managers has elected (with the concurrence of a majority of the votes held by the disinterested Managers) to cause the Company or its Subsidiaries to pursue the opportunity to acquire, construct or invest in the Subject Assets. Failure by the Board of Managers to provide such notice within such 30-day period shall be deemed to constitute a decision not to pursue such opportunity. If, at any time, the Board of Managers abandons such opportunity with the approval of a majority of the votes held by the disinterested Managers (as evidenced in writing by the Board of Managers following the request of such Member), such Member may pursue such opportunity.

(ii) If any Subject Assets which are permitted to be acquired, constructed or invested in by such Member (A) are not so acquired, constructed or invested in on or before the first anniversary of the later to occur of (x) the date that such Member is permitted to pursue such acquisition, construction project or investment pursuant to Section 6.4(c)(i) and (y) the date upon which all required governmental approvals to consummate such acquisition, construction project or investment have been obtained, or (B) are to be acquired, constructed or invested in on terms more favorable to such Member than were offered to the Company, then such opportunity must be reoffered to the Company in accordance with the Section 6.4(c)(i).

(iii) Notwithstanding Section 6.4(c)(i), in the event that any Member becomes aware of an opportunity to acquire, construct or invest in assets that include both Subject Assets and assets that are not Subject Assets and the Subject Assets have a fair market value (as determined in good faith by the governing authority of such Member) equal to or greater than $5 million but comprise less than 25% of the fair market value (as determined in good faith by the governing authority of such Member) of the total assets being considered for acquisition, construction or investment, then such Member may make such acquisition, construction or investment without first offering the opportunity to the Company or notifying the Board of Managers pursuant to Section 6.4(c)(i) provided that such Member complies with the following procedures:

(A) Within 90 days after the consummation of the acquisition, construction or investment, as the case may be, by such Member of the Subject Assets, such Member shall notify the Board of Managers in writing of such acquisition, construction or investment and offer the Company the opportunity to purchase such Subject Assets in accordance with this Section 6.4(c)(iii) (the "*Offer*"). The Offer shall set forth the proposed terms by which the Company or its Subsidiaries may purchase the Subject Assets (including the price for the Subject Assets, which shall be the purchase price paid by such Member for the Subject Assets reasonably determined by the Member as the portion of the total

purchase price allocated to the Subject Assets) and, if such Member desires to utilize the Subject Assets, the proposed commercially reasonable terms on which the Company will enable such Member to utilize the Subject Assets. As soon as practicable, but in any event within 30 days after receipt of such written notification, the Board of Managers shall notify such Member in writing that either (x) the Board of Managers has elected (with the concurrence of a majority of the votes held by the disinterested Managers) not to cause the Company or any Subsidiary to purchase the Subject Assets, in which event such Member shall be forever free to continue to own or operate such Subject Assets, or (y) the Board of Managers has elected (with the concurrence of a majority of the votes held by the disinterested Managers) to cause the Company or a Subsidiary to purchase the Subject Assets, in which event the following procedures in Sections 6.4(c)(iii)(B) shall apply.

(B) The Company or a Subsidiary shall purchase the Subject Assets as soon as commercially practicable after such agreement has been reached or enter into an agreement with such Member to provide services in a manner consistent with the Offer.

(d) *Enforcement.*

(i) The Members hereby agree and acknowledge that the Company and its Subsidiaries do not have an adequate remedy at law for the breach by any Member of the covenants and agreements set forth in this Section 6.4, and that any breach by any Member of the covenants and agreements set forth in this Section 6.4 would result in irreparable injury to the Company and its Subsidiaries. The Members hereby further agree and acknowledge that the Company or any Subsidiary may, in addition to the other remedies which may be available to the Company or any Subsidiary, file a suit in equity to enjoin the Members from such breach, and consent to the issuance of injunctive relief relating to this Agreement. No Person, directly or indirectly controlled thereby shall be liable for the failure of any other Person, directly or indirectly, controlled thereby to comply with this Section 6.4.

(ii) If any court determines that any provision of this Section 6.4 is invalid or unenforceable, the remainder of such provisions shall not thereby be affected and shall be given full effect without regard to the invalid provision. If any court construes any provision of this Section 6.4, or any part thereof, to be unreasonable because of the duration of such provision or the geographic scope thereof, such court shall have the power to reduce the duration or restrict the geographic scope of such provision and to enforce such provision as so reduced or restricted.

6.5 Acknowledgement Regarding Business Opportunities.

(a) Each of the Members acknowledges and agrees that the Investor Parties and their respective Affiliates have made or are engaged in, prior to the date hereof, and may make or engage in, on and after the date hereof, investments in and other transactions with and with respect to (whether by acquisition, construction, investment in debt or equity securities of any

Person or otherwise) Persons or assets engaged in businesses that directly or indirectly compete with the business of the Company as conducted from time to time or as expected to be conducted from time to time (each an "*Other Investment*"). Except as otherwise expressly set forth in Section 6.4 and Section 6.5(b), the Members agree that any involvement, engagement or participation of the Investor Parties and their respective Affiliates (including any Manager who is an Affiliate of any Investor Party) in an Other Investment, even if competitive with the Company, shall not be deemed wrongful or improper or to violate any duty express or implied under applicable Law. For the avoidance of doubt, an Investor Party shall not be deemed to violate this Section 6.5 if it or any of its Affiliates invests in a fund or other entity (whether or not the Investor Party or its Affiliates Controls such fund or entity) that makes an investment that directly or indirectly competes with the Company or its Subsidiaries.

(b) Each Member hereby renounces any interest or expectancy in any business opportunity, transaction or other matter in which any of the Investor Parties or any of their respective Affiliates participates or desires or seeks to participate (each, a "*Business Opportunity*") other than a Business Opportunity that (i) is presented to any Manager who is an Affiliate of such Investor Party solely in such individual's capacity as a Manager (whether at a meeting of the Board of Managers or otherwise) and with respect to which, prior to such Business Opportunity being presented to such Manager, such Investor Party did not independently receive notice or was not otherwise pursuing or aware of such Business Opportunity or (ii) is identified to any Manager who is an Affiliate of such Investor Party solely through the disclosure of information on behalf of the Company to such Manager and in each case, prior to such Business Opportunity being identified to such Manager, such Investor Party did not independently receive notice or was not otherwise pursuing or aware of such Business Opportunity (each Business Opportunity other than those referred to in clauses (i) or (ii) of this Section 6.5(b) is referred to as a "*Renounced Business Opportunity*" and each Business Opportunity referred to in clauses (i) and (ii) of this Section 6.5(b) is referred to as a "*Company Business Opportunity*"). Where an Investor Party or any of its Affiliates desires or seeks to participate in a Company Business Opportunity, such Investor Party will promptly notify the Board of Managers in writing and shall deliver to the Board of Managers all information prepared by or on behalf of such Investor Party or any of its Affiliates relating to such Company Business Opportunity. As soon as practicable, but in any event within 60 days after receipt of such written notification and information, the Board of Managers shall notify such Investor Party in writing that either (i) the Board of Managers has elected not to pursue such Company Business Opportunity or (ii) the Board of Managers has elected to pursue such Company Business Opportunity. If the Board of Managers fails to provide such notice within such period of 60 days, the Board of Managers will be deemed to have elected not to pursue such Company Business Opportunity. If the Board of Managers elects or is deemed to elect not to pursue such Company Business Opportunity, such Investor Party or any of its Affiliates may pursue such Company Business Opportunity and such Company Business Opportunity shall thereafter be deemed to be a Renounced Business Opportunity for all purposes hereunder. Neither such Investor Party nor any of its Affiliates, including any Manager who is an Affiliate of such Investor Party, shall have any obligation to communicate or offer any Renounced Business Opportunity to the Company or its Subsidiaries, and such Investor Party or any of its Affiliates may pursue for itself or direct, sell, assign or transfer to a Person other than the Company or its Subsidiaries any Renounced Business Opportunity.

(c) Each Member that is an employee of the Company, any of its Subsidiaries or the Management Company (an "Employee Member") hereby agrees to disclose and make available to the Company each and every investment and business opportunity that such Employee Member becomes aware of in his or her capacity as an Employee Member of the Company or otherwise; provided that no such disclosure or offer shall be required (a) with respect to business opportunities which are not within or reasonably related to the existing or contemplated scope and purpose of the Company's businesses at the time or (b) if otherwise agreed in writing by the Board of Managers. The Board of Managers may, in its sole discretion, waive the terms and provisions of this Section 6.5(c) with respect to any such Employee Member.

(d) Each of the Members hereby agrees that any claims against, actions, rights to sue, other remedies or other recourse to or against any Investor Party or any of its Affiliates for or in connection with any Renounced Business Opportunity or other investment activity, transaction activity or other matters described in Section 6.5(a), whether arising in common law or equity or created by rule of Law, statute, constitution, contract or otherwise, are expressly released and waived by each Member to the fullest extent permitted by Law.

(e) Notwithstanding anything in this Agreement to the contrary, each of the Members acknowledges and agrees that the Investor Parties and their respective Affiliates (including any Manager who is an Affiliate of an Investor Party) have obtained, prior to the date hereof, and are expected to obtain, on and after the date hereof, confidential information from other companies in connection with Renounced Business Opportunities or other investment activities, transaction activities or other matters described in Section 6.5(a). Each of the Members hereby agrees that (i) neither such Investor Party nor any of its Affiliates (including any Manager who is an Affiliate of such Investor Party) has any obligation to use any such confidential information in connection with the business, operations, management or other activities of the Company or its Subsidiaries or to furnish to the Company, its Subsidiaries or any Member any such confidential information and (ii) any claims against, actions, rights to sue, other remedies or other recourse to or against such Investor Party or any of its respective Affiliates (including any Manager who is an Affiliate of such Investor Party) for or in connection with any such failure to use or to furnish such confidential information, whether arising in common law or equity or created by rule of law, statute, constitution, contract or otherwise, are expressly released and waived by each Member to the fullest extent permitted by Law.

(f) The Members agree that, to the extent any court holds that any activity relating to any Other Investment or Renounced Business Opportunity is a breach of a duty to the Company or its Members, the Members hereby waive any and all claims and causes of action that they or the Company may have in connection with such activity; provided that this sentence shall not constitute a waiver by the Members of any disclosure of Confidential Information by the Institutional Investors in violation of Section 7.5. The Members further agree that the waivers and agreements in this Agreement identify certain types and categories of activities that do not violate any duty of the Institutional Investors to the Company or its Members and that such types and categories are not manifestly unreasonable. The waivers and agreements in this Agreement apply equally to activities that have been conducted in the past and to activities conducted in the future.

(g) The provisions of this Section 6.5 shall be subject to the provisions of Section 6.4, it being the intention of the Members that any Business Opportunity that constitutes a Restricted Business in accordance with Section 6.4 shall be governed by the provisions of Section 6.4 and not this Section 6.5.

6.6 Resolution of Conflicts of Interest.

Unless otherwise expressly provided in this Agreement, whenever a potential conflict of interest exists or arises between any Member or any of its Affiliates, on the one hand, and the Company, any of its Subsidiaries, any other Member or any of their respective Affiliates, on the other, any resolution or course of action by the Company or a Member in respect of such conflict of interest shall be deemed approved by all Members, and shall not constitute a breach of this Agreement or of any duty stated or implied by Law or equity, if (i) the resolution or course of action in respect of such conflict of interest is approved by (x) a majority of the votes held by the disinterested Managers or (y) only if such conflict involves the Management Incentive Members, the vote of Members holding a majority of the outstanding Management Incentive Units (excluding Management Incentive Units owned by any Member who is a Defaulting Member) or (ii) the Company receives a written opinion from a nationally recognized investment bank or financial advisory firm approved by a majority of the votes held by the disinterested Managers stating that the proposed resolution or course of action is fair from a financial point of view to the Company and the Members who are not the subject of the potential conflict of interest (or, if all Members may be affected by such potential conflict of interest, to the Company and all Members). For the avoidance of doubt, if the resolution or course of action by the Company or a Member in respect of such conflict of interest otherwise requires any other approval under this Agreement, then such approval shall nonetheless be required notwithstanding the foregoing terms of this Section 6.6.

ARTICLE 7
BOOKS, REPORTS, BUDGET AND CONFIDENTIALITY

7.1 Books and Records; Capital Accounts.

(a) The Company shall keep the books of account for the Company in accordance with the terms of this Agreement. Such books shall be maintained at the principal office of the Company. The Company shall allow each Institutional Investor or its designated representative the right to consult and advise management of the Company, to visit and inspect the offices and properties of the Company and to inspect and copy the books and records of the Company, at such times as the Institutional Investor or its designated representative shall reasonably request.

(b) The Company shall maintain for each Member a separate Capital Account in accordance with Section C.1.2 of Exhibit C.

7.2 Bank Accounts.

The Company shall cause one or more accounts to be maintained in a bank (or banks) which is a member of the Federal Deposit Insurance Corporation, which accounts shall be used for the payment of the expenditures incurred by the Company in connection with the business of the

Company, and in which shall be deposited any and all receipts of the Company. Company funds may be invested in such money market accounts or other investments as the Board of Managers shall determine to be necessary or appropriate.

7.3 Reports.

The Company shall provide each Manager and each Institutional Investor with the following financial statements and reports at the times indicated below:

(a) Monthly within 30 days after the end of each fiscal month of the Company (excluding the last fiscal month of each Fiscal Year and each Fiscal Quarter), beginning with the first full month to end after the date hereof, the unaudited financial statements prepared in accordance with GAAP, or such method of accounting as determined by the Board of Managers in its sole discretion, with respect to such fiscal month, including statements of operations, balance sheets, cash flow statements and statements of owners' equity, setting forth in each case in comparative form the figures for the comparable month of the previous year.

(b) Quarterly within 30 days after the end of each Fiscal Quarter, unaudited financial statements prepared in accordance with GAAP, or such method of accounting as determined by the Board of Managers in its sole discretion, with respect to such Fiscal Quarter, including statements of operations, balance sheets, cash flow statements and statements of owners' equity, in each case, setting forth in comparative form the figures for the previous year and a comparison to budgeted amounts. Such financial statements shall be subject to audit by any of the Institutional Investors at any time at its request at its own expense.

(c) Annually within 60 days after the end of each Fiscal Year, financial statements prepared in accordance with GAAP, or such other method of accounting as determined by the Board of Managers in its sole discretion, including statements of operations, balance sheets, cash flow statements and statements of owners' equity with respect to such Fiscal Year, setting forth in each case in comparative form the figures for the previous year, which financial statements shall be audited by an independent certified public accounting firm selected and approved in accordance with Section 5.11(a)(xix).

(d) As soon as available, any annual reports, quarterly reports and other periodic reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, in each case actually prepared by the Company or its Affiliates to the extent the Company or any of its Affiliates is required by law or pursuant to the terms of any outstanding securities to prepare such reports.

(e) Within 75 days after the end of each Fiscal Year, the Company's Form 1065, all information needed to determine each Member's share of depletable basis, cost depletion and percentage depletion, a Schedule K-1 for such Fiscal Year and such other United States federal and state income tax reporting information, if any, as is required by law.

(f) Within 45 days after the end of the Second and Fourth Fiscal Quarters of each Fiscal Year, a reserve report for the Company as of the last day of each such Fiscal Quarter prepared by an independent petroleum engineering firm selected and approved by the Board of Managers that sets forth with respect to the Company as a whole, proved reserves, future net

revenues relating thereto (based upon pricing and other assumptions specified by the Board of Managers) and the discounted present value of such future net revenues (the rate of discount to be specified by the Company).

(g) Quarterly within 30 days after the end of each Fiscal Quarter of each Fiscal Year, an update of the reserve report referenced in Section 7.3(f) as of the last day of each such Fiscal Quarter, as applicable, which update shall be prepared by the employees of the Company (based upon pricing and other assumptions specified by the Board of Managers).

(h) Quarterly within 30 days after the end of each Fiscal Quarter, a quarterly activity report that includes a management discussion of Company business, operations and results for such Fiscal Quarter, the Board of Manager's plan for the upcoming Fiscal Quarter and a discussion of any issues or events that the Board of Managers determines are likely to have a material effect on the Company's operations and results for the upcoming Fiscal Quarter.

(i) At least three days prior to each scheduled quarterly board meeting, board books for the Board of Managers.

(j) Such other reports and financial information relating to the Company as the Board of Managers shall determine or any Institutional Investor may reasonably request from time to time, such as information with respect to matters relating to the business and affairs of the Company, including, without limitation, significant changes in management personnel and compensation of employees, introduction of new lines of business, important acquisitions or dispositions, copies (each no later than three Business Days after receipt thereof by the Company) of Drilling Notices and Commitment Cash Calls under the Development Agreement, information required by any Institutional Investor for purposes of the matters covered by Section 11.5(b), significant research and development programs, the purchasing or selling of important trademarks, licenses or concessions or the proposed commencement or compromise of significant litigation.

7.4 Budget.

(a) *Initial Budget.* The Board of Managers has approved the Initial Budget. The Initial Budget will be the Approved Budget of the Company from the Effective Date until the adoption of a subsequent Approved Budget by the Board of Managers.

(b) *Budget Proposals.* At least 10 days prior to the scheduled date of each quarterly meeting of the Board of Managers, the Company shall furnish to the Managers (and Board Observers) (i) an updated outline of the geographic scope of the Company's operations and (ii) a proposed revised budget estimating the revenues, expenses, capital expenditures, general and administrative expenses and additional Capital Calls in connection with the Company's operations during the next succeeding 12 calendar months.

(c) *Budget Approval.* At each quarterly board meeting the Board of Managers shall discuss the proposed budget and approve, reject or make such revisions thereto as the Board of Managers may agree to be necessary and proper. If the proposed budget, as may be revised by the Board of Managers, is approved by the Board of Managers, then such proposed budget

shall be deemed thereafter to constitute the "*Approved Budget*" for all purposes hereof, subject to amendment from time to time by the Board of Managers. Each Approved Budget shall supersede all prior Approved Budgets. A budget may only be approved by the Board of Managers.

7.5 Confidentiality.

(a) No Member nor any of its Affiliates shall use, publish, disseminate or otherwise disclose, directly or indirectly, any Confidential Information that should come into the possession of such Member or its Affiliates other than (i) for the purpose of conducting the business of the Company and its Subsidiaries or performing its duties and obligations to the Company hereunder or under an Employment Agreement; (ii) as required (A) due to a subpoena or court order or (B) if testifying in a judicial or regulatory proceeding pursuant to the order of a judge or administrative law judge after requesting confidential treatment for such Confidential Information; (iii) to the Member's partners, members, managers, directors, officers, employees, advisors and representatives, and potential Transferees as permitted by this Agreement; (iv) if an Institutional Investor, such Institutional Investor may disclose Confidential Information to its investors (other than investors in a publicly-traded company, except as provided in clause (v)) or (v) if an Institutional Investor, such Institutional Investor may disclose Confidential Information to any regulatory or other governmental authority (including the U.S. Securities and Exchange Commission) that regulates such Institutional Investor. For the avoidance of doubt, if any Member or its Affiliates is a publicly-traded company, such Member or its Affiliates may disclose Confidential Information to the public investors in such entity in accordance with, and as required by, law, regulation, subpoena or court order of any governmental body (including the U.S. Securities and Exchange Commission) or national stock exchange. If a Member is required by law, regulation, subpoena or court order to disclose information (other than with respect to (x) information disclosed by a publicly-traded company in accordance with the rules and regulations of the U.S. Securities and Exchange Commission or a national stock exchange and (y) information disclosed to banking regulators) that would otherwise be Confidential Information under this Agreement, such Member shall immediately notify the Managers of such requirement and provide the Managers the opportunity to resist such disclosure by appropriate proceedings.

(b) Each Member shall, and shall cause each of its Affiliates, and its and their respective directors, officers, members, partners, investors, employees, representatives and agents (i) to comply with this Section 7.5, (ii) to refrain from using any Confidential Information other than in connection with the conduct of the business of the Company and (iii) to refrain from disclosing any Confidential Information to a Person known to be a competitor of the Company; provided that, the foregoing shall not prohibit the respective Institutional Investors from utilizing Confidential Information in connection with Other Investments if such Confidential Information is acquired from a source other than the Company, provided that source is not known by the Institutional Investors to be bound by a confidentiality agreement with, or other contractual or legal obligation of confidentiality to, the Company with respect to such Confidential Information. In connection with the foregoing, the Institutional Investors represent that their respective partnership agreements, limited liability company agreements or company policies, as applicable, contain provisions that generally require, subject to certain limited exceptions, each employee, limited partner or member, as applicable, to maintain in

strict confidence any and all material, nonpublic information concerning the operations, business, or affairs of entities in which they invest, including the Company.

(c) No Member nor any of its Affiliates shall publish, disseminate or otherwise disclose, directly or indirectly, to any other party any information relating to the terms of this Agreement, the Company, any other Member or any of the investors of any Institutional Investor without the prior written consent of (i) a majority in interest of the other Members, (ii) if such communication mentions any Member specifically, such Member or (iii) if such communication mentions the investors of any Institutional Investor specifically, such Institutional Investor, which consent, in each case, will not be unreasonably withheld; provided however, that a Member may disclose such information (A) to such Member's spouse, accountants, financial advisors and legal counsel; (B) with respect to Institutional Investors, to (1) such Institutional Investor's investors (other than investors in a publicly-traded company, except as provided in clause (C)) and (2) banking regulators and (C) as required by law, regulation, subpoena or court order of any governmental body (including the U.S. Securities and Exchange Commission) or national stock exchange.

ARTICLE 8
DISSOLUTION, LIQUIDATION AND TERMINATION

8.1 Dissolution.

The Company shall be dissolved upon the earliest to occur of any of the following:

(a) the sale or disposition of all or substantially all of the property of the Company for cash, Marketable Securities or a combination thereof;

(b) at the election of the Board of Managers and with Supermajority Member Approval to dissolve the Company at any time; and

(c) as otherwise provided by law.

8.2 Liquidation and Termination.

Upon dissolution of the Company, the Board of Managers or a Person or Persons selected by the Board of Managers shall act as liquidator who shall have full authority to wind up the affairs of the Company and make final distribution as provided herein. The liquidator shall continue to operate the Company properties with all of the power and authority of the Board of Managers. The steps to be accomplished by the liquidator are as follows:

(a) As promptly as possible after dissolution and again after final liquidation, the liquidator, if requested by any Member, shall cause a proper accounting to be made by the Company's independent accountants of the Company's assets, liabilities and operations through the last day of the month in which the dissolution occurs or the final liquidation is completed, as appropriate.

(b) The liquidator shall sell all properties and assets of the Company for cash as promptly as is consistent with obtaining the best price thereon provided, however, that upon

the consent of the Board of Managers, the liquidator may elect not to sell all or any portion of such properties and assets and instead distribute such properties and assets in kind, subject to the remaining provisions of this Section 8.2.

(c) Prior to making any distribution to the Members of properties or assets of the Company (including the proceeds from any sale described in Section 8.2(b)), the liquidator shall pay all of the debts and liabilities of the Company (including all expenses incurred in liquidation) or otherwise make adequate provision therefor (including the establishment of a cash escrow fund for contingent liabilities in such amount and for such term as the liquidator may reasonably determine). After making such payments and except for amounts reserved to make such payments, the liquidator shall then distribute all cash and other property pursuant to Section 4.2(a).

(d) Except as expressly provided herein, the liquidator shall comply with any applicable requirements of the Act and all other applicable laws pertaining to the winding up of the affairs of the Company and the final distribution of its assets. Upon the completion of the distribution of Company cash and property as provided in this Section 8.2 in connection with the liquidation of the Company, the Certificate and all qualifications of the Company as a foreign limited liability company in jurisdictions other than the State of Delaware shall be canceled and such other activities as may be necessary to terminate the Company shall be taken by the liquidator.

(e) Notwithstanding any provision in this Agreement to the contrary, no Member shall be obligated to restore a deficit balance in its Capital Account at any time.

ARTICLE 9
TRANSFER OF INTERESTS

9.1 Limitation on Transfer.

(a) Except as provided in Section 9.2, no Member, nor its successors, transferees or assigns, shall Transfer all or any portion of its Interest without compliance with the terms and conditions of this Agreement and any attempted Transfer of an Interest that is not made in accordance with this Agreement shall be null and void and shall have no effect. In addition, and subject to Section 9.2, without the prior consent of the Board of Managers, no Member that is an Entity may cause or permit an interest, direct or indirect, in itself to be Transferred, in a single transaction or series of related transactions, if the Persons Controlling such Member prior to such Transfer would cease to Control such Member following such Transfer. Any Transfer not permitted hereby shall be null and void and shall have no effect. For purposes of this Section 9.1(a), Transfers of interests in an Entity that is a publicly-traded company shall be deemed not to constitute an indirect Transfer of a Member.

(b) Notwithstanding that a Member has obtained the right to Transfer any Interest in any manner provided in this Article 9, such Transfer shall not be permitted unless and until (i) the purchaser, assignee, donee or transferee thereof agrees in writing to take and accept such Interest subject to all of the restrictions, terms and conditions contained in this Agreement, any Employment Agreement or Award Letter, the same as if it were a signatory party hereto or

thereto and (ii) to the extent that the Capital Commitment associated with such Transferred Interest, or portion thereof, has not been completely funded, such purchaser, assignee, donee or transferee shall be required to demonstrate to the Board of Managers, in its sole discretion, that such transferee has the financial ability to fund the unfunded portion of such Capital Commitment. The Company will not be required to recognize any permitted assignment of an Interest until the instrument conveying such Interest has been delivered to the Company.

(c) Notwithstanding anything to the contrary in this Article 9, no portion of an Interest may be Transferred, and no Member that is an Entity may cause or permit a direct or indirect interest in itself to be Transferred, if the Board of Managers determines in good faith that any such Transfer could result in (i) a termination of the Company pursuant to section 708(b)(1)(B) of the Code or (ii) the classification of the Company as a publicly traded partnership under section 7704 of the Code, unless the Board of Managers, it its sole discretion, determines to waive the provisions of this Section 9.1(c).

9.2 Permitted Transfers.

(a) The Transfer restrictions of Section 9.1(a) shall not apply to any Transfer of Interests (i) by a Member to such Member's Permitted Transferees (subject to Section 9.2(b) and provided that Management Incentive Units will not be transferrable without the written consent of the Board of Managers and then only for estate planning purposes), (ii) in kind by an Institutional Investor through a distribution to its partners or investors or to any partnership, corporation or other entity all of the equity securities of which are beneficially owned directly or indirectly by such Persons, (iii) by an Institutional Investor to an Affiliate thereof, (iv) pursuant to a Drag-Along Notice, (v) consisting of Common Units pursuant to a Tag-Along Notice, (vi) pursuant to any Final Exit Event, (vii) pursuant to any Internal Restructure as described in Section 9.8, (viii) approved by a majority of the votes held by disinterested Managers or (ix) consisting of Common Units occurring on or following the third anniversary of the Effective Date.

(b) A Permitted Transferee of any Interests that have been Transferred to such Permitted Transferee in compliance with the provisions of this Article 9 shall not be entitled to make any further Transfers in reliance upon this Section 9.2, except for a Transfer of such Transferred Interests back to such original holder or to another Permitted Transferee of such original holder or to a Person to whom such Transfer is permitted by such original holder under this Section 9.2. A Permitted Transferee must assume all of the obligations of the original holder of the Interests under and agree to comply with the provisions of this Agreement and must acknowledge that the Interests Transferred to such Permitted Transferee shall be subject to the restrictions, obligations and remedies under this Agreement with respect to Interests held by the original holder of such Interests as if they were still held by such holder. If a Permitted Transferee of Interests at any time ceases to be a Permitted Transferee of such original holder, then such former Permitted Transferee shall promptly Transfer such Transferred Interests back to such original holder or to another Permitted Transferee of such original holder, and if the former Permitted Transferee fails to make such a Transfer within 15 days of such former Permitted Transferee ceasing to be a Permitted Transferee of such original holder, then the Company may, at its option, cause the forfeiture of such Interests to the Company for no consideration.

9.3 Right of First Refusal.

(a) Any Member who proposes to make a Transfer of Common Units ("*Right of First Refusal Units*") to a Person who is not a Permitted Transferee of such Member, other than with respect to a Drag-Along Transaction or the related right of first offer under Section 9.7, shall give written notice (the "*Right of First Refusal Notice*") to the Company and to each Eligible Investor setting forth the purchase price and the terms and conditions upon which such selling Member is proposing to Transfer Common Units. Thereafter, each Eligible Investor shall have the right but not the obligation to purchase or otherwise acquire up to its pro rata share of such Right of First Refusal Units (the "*Right of First Refusal Option*"). The Eligible Investors may exercise such Right of First Refusal Option within 20 Business Days of receiving the Right of First Refusal Notice (the "*Right of First Refusal Notice Period*"), up to their respective pro rata share of the Right of First Refusal Units, upon the terms and conditions and for the purchase price set forth in the Right of First Refusal Notice. Those Eligible Investors who have elected to purchase their full pro rata share and who have notified such selling Member within the Right of First Refusal Notice Period that they desire to purchase more than their full pro rata share of the Right of First Refusal Units may purchase their respective pro rata share of any remaining balance of the Right of First Refusal Units. After the expiration of the Right of First Refusal Notice Period, the selling Member shall have the power to sell all of the Right of First Refusal Units that have not been purchased to one or more third parties, but only upon the terms and conditions and for the purchase price in each case no less favorable to the selling Member than those set forth in the Right of First Refusal Notice and subject to further compliance with Section 9.6(b) regarding tag-along rights. In each case, the phrase "pro rata share" as used in this Section 9.3(a) shall mean such Eligible Investor's pro rata share based on the Eligible Investor's respective Fully-Funded Percentage Interest.

(b) Each Potentially Restricted Member has notified the Company and the Members that one or more laws, rules, regulations or government orders that may be enacted in the future (including without limitation those promulgated under the Dodd-Frank Wall Street Reform and Consumer Protection Act, as amended) could limit the ability of a Potentially Restricted Member and/or its Affiliates from directly or indirectly holding certain investments, including the Common Units or any other Interests. In the event the effect of any such law, rule, regulation or government order is later determined at any time by a Potentially Restricted Member in its reasonable and good faith judgment (in such case such Potentially Restricted Member shall submit an opinion of its internal counsel if requested by the Company as to such determination) or by one of its regulators to prohibit or restrain such Potentially Restricted Member from continuing to hold Common Units or any other Interests, the Company and the Members hereby acknowledge that such Potentially Restricted Member may, after complying with the first refusal rights of Eligible Investors in Section 9.3(a), but without the need to comply with the provisions of Section 9.6(b) regarding tag-along rights or any other provision in this Agreement restricting such Potentially Restricted Member's legal right to Transfer its Common Units or any other Interests, Transfer its Common Units and any other Interests held by such Potentially Restricted Member to an unaffiliated third party.

9.4 Repurchase Option.

Each Employee Member and each Affiliate and Permitted Transferee of such Employee Member that then holds any Interests (collectively. the "*Repurchase Interest Holders*") grants the Company or its nominee or assignee an option, exercisable by the Board of Managers in its sole discretion, to repurchase all or any portion of such Repurchase Interest Holders' Interests (including any Common Units and vested Management Incentive Units held by the Repurchase Interest Holders after giving effect to any forfeiture thereof as provided in this Agreement, any Employment Agreement or any Award Letter) (the "*Repurchase Interests*"), for an amount equal to the Fair Market Value of the Repurchase Interests pursuant to the terms and conditions set forth in this Section 9.4. For purposes of this Section 9.4, Fair Market Value shall be determined based on the assumption that the assets of the Company were liquidated for their fair market value and the proceeds of such liquidation were distributed to the Members after all debts and obligations of the Company were paid. The Fair Market Value shall not take into account any discount for minority status or lack of liquidity. Such option granted to the Company or its designee or assignee shall be exercisable at any time during the 90-day period beginning on the date such Employee Member's employment is terminated for any reason (such option is referred to herein as the "*Repurchase Option*" and the Fair Market Value of the Repurchase Interests referred to herein as the "*Repurchase Price*"). The Board of Managers and the Employee Member will attempt in good faith to agree on the Repurchase Price of the Repurchase Interests as of the date on which the Board of Managers, or its nominee or assignee, notifies the Repurchase Interest Holders of its intent to exercise the Repurchase Option (the "*Repurchase Option Exercise Notice*"). If (i) an agreement on the Repurchase Price is not reached within 16 days after the date of the Repurchase Option Exercise Notice and (ii) the Repurchase Interest Holders hold more than 150,000 vested Management Incentive Units, then the Repurchase Price of the Repurchase Interests shall be determined by a qualified independent appraiser to be mutually agreed upon by such Employee Member and the Board of Managers, provided that if they are unable to mutually agree on an appraiser within 10 days, the Company shall apply to the American Arbitration Association ("*AAA*") in Houston, Texas for an appraiser having experience in the oil and natural gas industry and in private equity to be appointed. In all other circumstances, the Repurchase Price shall be determined by the Board of Managers in its reasonable judgment. The expenses of any appraiser shall be borne 50% by the Company and 50% by the Employee Member, and, if there is more than one Repurchase Interest Holder, then the 50% expense allocation shall be apportioned among them according to their respective Fully-Funded Percentage Interest (or MIU Percentages if all are not Common Unitholders). Once the Repurchase Price has been determined, the Board of Managers, or its nominee or assignee, will make an election whether or not to purchase the Repurchase Interests by delivering written notice (the "*Repurchase Notice*") to the Repurchase Interest Holders within 30 days of the date that the Repurchase Price has been determined. The Repurchase Notice shall set forth (i) a date or time of not more than 60 days from the delivery date on which closing of the purchase of the Repurchase Interest will occur and (ii) the portion of the Repurchase Interest to be purchased. Notwithstanding the foregoing provisions of this Section 9.4, if the Employee Member has an Employment Agreement and the Employee Member terminated his or her employment for Good Reason (as defined in any such Employment Agreement), then the Repurchase Interest Holders may retain their Common Units by so notifying the Company in writing within 10 days after receipt of the Repurchase Notice (the "*Retention Exercise Notice*"). If the Company receives a timely Retention Exercise Notice, then the Repurchase Notice shall apply only to vested Management Incentive Units and the portion of the Repurchase Price attributed to such vested

Management Incentive Units. An Employee Member whose employment has terminated and each Permitted Transferee of such Employee Member shall not Transfer or attempt to Transfer its Repurchase Interests during the period in which such option is exercisable or after the exercise of such option. Any Transfer or attempted Transfer in violation of this Section 9.4 shall be null and void, and the Company shall not record such Transfer on its books or treat any such purported transferee of such Repurchase Interests as the owner of the Repurchase Interests for any purpose. The Company may assign its rights under this Section 9.4 to a party who has the financial ability to pay the full purchase price in cash for the Repurchase Interests as provided herein, subject to approval of the Board of Managers, excluding any Repurchase Interest Holder. Any subsequent Transfer or attempted Transfer shall continue to be subject to this Article 9. The exercise by the Company of the Repurchase Option and the other rights granted under this Section 9.4 shall be determined on behalf of the Company by the Board of Managers, excluding any Repurchase Interest Holder. The foregoing provisions of this Section 9.4 are subject to the terms of any Employment Agreement or Award Letter.

9.5 Transferees.

The transferee of any Interest that has been Transferred in compliance with the provisions of this Article 9 shall be entitled to receive the share of Company income, gains, losses, deductions, credits and distributions to which its transferor would have been entitled with respect to such Interest; provided, however, that such transferee shall not be so entitled and shall not become a Member of the Company with respect to such Interest unless: (a) the instrument of assignment so provides; (b) a majority of votes held by the Managers (other than any Manager appointed by the transferor, if applicable), in its sole discretion, consents to the admission of such transferee as a Member; provided, consent of the Board of Managers under this clause (b) shall not be required if such transferee is a Permitted Transferee of the transferor unless and until such transferee is no longer a Permitted Transferee of the transferor (because, for example, the transferor no longer Controls such transferee) in which case such transferee shall be an assignee hereunder but not a Member (unless the Board of Managers consents to the admission of such transferee at such time as a Member); and (c) such transferee agrees in writing to be bound as a Member by this Agreement. Upon becoming a Member, such transferee shall have all of the rights and powers of, shall be subject to all of the restrictions applicable to, shall assume all of the obligations of, and shall succeed to the status of, its predecessor, and shall in all respects be a Member under this Agreement. Any transferee of an Interest who is admitted to the Company as a Member shall be considered for all purposes to be a Member of the same class as his transferor. The use of the term "*Member*" in this Agreement shall be deemed to include any such additional Members. Until such transferee is admitted as a Member pursuant to this Section 9.5, (x) such transferee shall not be entitled to participate in the management of the Company or to exercise any voting or other rights or powers of a Member, except for the rights described in the first sentence of this Section 9.5 and (y) the transferor Member shall continue to be a Member and to be entitled to exercise any rights or powers of a Member with respect to the Interest Transferred. A Permitted Transferee of any Investor Party in a transfer designated in Section 9.2(a)(ii) and Section 9.2(a)(iii), and a transferee of Potentially Restricted Member in a transfer designated in Section 9.3(b), shall be admitted as a Member subject only to satisfaction of clause (c) hereof.

9.6 Drag-Along and Tag-Along Rights.

(a) *Drag-Along Rights.*

(i) Subject to the prior compliance with the provisions of Section 9.7 relating to the right of first offer described therein, subsequent to the third anniversary of the Effective Date and prior to a Final Exit Event or an Initial Public Offering, if Common Unitholders holding in excess of 50% of the then outstanding Common Units (the "*Dragging Members*") propose to sell Control of the Company to a non-Affiliate third-party by way of a merger, consolidation or Transfer of Common Units or otherwise (any such transaction, a "*Drag-Along Transaction*"), such Dragging Members shall have the right to require all (but not less than all) of the other Members (each, a "*Drag-Along Member*") to Transfer their Interests in such Drag-Along Transaction (without the need for the Drag-Along Members' approval) structured as a Transfer of Common Units. Proceeds from a Drag-Along Transaction (A) may include proceeds that are subject to earn-outs or similar arrangements and (B) will be distributed consistent with Section 4.2, treating all unvested Management Incentive Units as vested and distributing all Retained Amounts as if the Drag-Along Transaction were a liquidation as described in Section 8.2. Notwithstanding the foregoing, the proceeds received in a Drag-Along Transaction may not include consideration other than cash or Marketable Securities unless the Drag-Along Transaction is approved by Supermajority Member Approval.

(ii) The Dragging Members shall provide each Drag-Along Member notice of the terms and conditions of such proposed Drag-Along Transaction (the "*Drag-Along Notice*") not later than 10 Business Days prior to the closing of the proposed Drag-Along Transaction. The Drag-Along Notice shall contain a true and complete copy of any and all available documents constituting the agreement to transfer and, to the extent not set forth in the accompanying documents, the price offered for the Interests, all information reasonably available to the Dragging Members regarding the acquirer, all other material terms and conditions of the proposed Drag-Along Transaction and, in the case of a proposed Drag-Along Transaction in which the consideration payable for the Interests consists in whole or in part of consideration other than cash, such information relating to such other consideration as is reasonably available to the Dragging Members. Each Drag-Along Member shall be required to participate in the Drag-Along Transaction on the terms and conditions set forth in the Drag-Along Notice, this Section 9.6(a) and Section 9.6(c). No Member shall have any dissenters' or appraisal rights in connection with the Drag-Along Transaction, and each Member hereby releases, and will execute such further instrument as the Company reasonably requests to further evidence the waiver of, such rights.

(iii) Within 5 Business Days following receipt of the Drag-Along Notice (the "*Drag-Along Notice Period*"), each Drag-Along Member must deliver to such Dragging Members (A) wire transfer instructions for payment of the purchase price for the Interests to be sold in such Drag-Along Transaction and (B) all other documents required to be executed in connection with such Drag-Along Transaction. Each Member (other than the Institutional Investors) hereby makes, constitutes, and appoints the Dragging Member holding the largest number of Common Units among Dragging Members, as its true and lawful attorney in fact for such person and in its name, place, and stead and for its use and benefit, to sign, execute, certify, acknowledge, swear to, file and record any

instrument that is now or may hereafter be deemed necessary by the Company in its reasonable discretion to carry out fully the provisions and the agreement, obligations, and covenants of such Member in this Section 9.6(a) in the event that such Member is or becomes a Drag-Along Member pursuant to this Section 9.6(a). Each Member (other than the Institutional Investors) hereby gives such attorney in fact full power and authority to do and perform each and every act or thing whatsoever requisite or advisable to be done in connection with such Member's obligations and agreements as a Drag-Along Member pursuant to this Section 9.6(a) as fully as such Member might or could do personally, and hereby ratifies and confirms all that any such attorney in fact shall lawfully do or cause to be done by virtue of the power of attorney granted hereby. The power of attorney granted pursuant hereto is a special power of attorney, coupled with an interest, and is irrevocable, and shall survive the bankruptcy, insolvency, dissolution or cessation of existence of the applicable Member.

(iv) If, at the end of the 90-day period after the date on which the Dragging Members give the Drag-Along Notice (which 90-day period shall be extended if any of the transactions contemplated by the Drag-Along Transaction are subject to regulatory approval until the expiration of five Business Days after all such approvals have been received, but in no event later than 120 days following the delivery of the Drag-Along Notice), the Drag-Along Transaction has not been completed on substantially the same terms and conditions set forth in the Drag-Along Notice, the Drag-Along Members shall no longer be obligated to sell their Interests pursuant to such Drag-Along Notice and the Dragging Members shall return to each Drag-Along Member any documents in the possession of the Dragging Members executed by or on behalf of such Drag-Along Member in connection with the proposed Drag-Along Transaction.

(v) Concurrently with the consummation of the Drag-Along Transaction, Dragging Members shall (A) notify the Drag-Along Members thereof, (B) cause the total consideration for the Interests of the Drag-Along Members transferred pursuant thereto to be remitted directly to the Drag-Along Members and (C) promptly after the consummation of the Drag-Along Transaction, furnish such other evidence of the completion and the date of completion of such transfer and the terms thereof as may be reasonably requested by the Drag-Along Members.

(vi) Notwithstanding anything contained in this Section 9.6(a), there shall be no liability on the part of the Dragging Members to the Drag-Along Members if the transfer of the Interests pursuant to this Section 9.6(a) is not consummated for whatever reason.

(vii) Notwithstanding anything contained in this Section 9.6(a), the obligations of the Drag-Along Members to participate in a Drag-Along Transaction are subject to the following conditions:

(A) upon the consummation of such Drag-Along Transaction, (1) all of the Members participating therein will receive the same form of consideration (except as provided in Section 9.6(c)) and (2) the aggregate consideration

received by the Members will be paid to the Members subject to the allocation provisions set forth in Section 8.2(c);

(B) no Member participating therein shall be obligated to pay any expenses incurred in connection with any unconsummated Drag-Along Transaction, and each Member shall be obligated to pay only its pro rata share (based on the amount of Interests disposed of) of expenses incurred in connection with a consummated Drag-Along Transaction to the extent such expenses are incurred for the benefit of all Members and are not otherwise paid by the Company or another person;

(C) without the written consent of a Drag-Along Member, such Drag-Along Member shall not be obligated with respect to (1) any representation or warranty other than (x) a representation and warranty that relates solely to such Drag-Along Member's title to its Interests, and its authority and capacity to execute and deliver the subject purchase and sale agreement or (y) a representation and warranty that relates to the Company and its operations which each Member is severally making to the seller (provided, that if such Member or an Affiliate of such Member is not actively involved in the day to day operations of the Company, any such representation shall be limited to such Member's knowledge), or (2) any indemnity obligation beyond a pro rata portion or in excess of the gross proceeds received by a Drag-Along Member (in each case, based on the value of consideration received by such Drag-Along Member in the Drag-Along Transaction) of the indemnity obligations which obligate the Dragging Members and all Drag-Along Members and then, such indemnity obligations shall be several and not joint or (3) any other continuing obligation on such Drag-Along Member in favor of any other person following the Drag-Along Transaction of such Drag-Along Member's Interests (other than obligations relating to representations and warranties that relate solely to such Drag-Along Member and not to any other Member or the indemnification obligation provided for in clause (2) above); and

(D) no Drag-Along Member shall be obligated to consummate such Drag-Along Transaction contemplated by the Drag-Along Notice with respect to its Interests unless the Dragging Members consummate such Drag-Along Transaction with respect to all (but not less than all) of their Interests on the terms and conditions contemplated by the Drag-Along Notice.

(b) *Tag-Along Rights.*

(i) Subject to prior compliance with the provisions of Section 9.3(a) relating to first refusal rights for the benefit of Eligible Investors, and prior to a Final Exit Event or an Initial Public Offering, any Member (an "*Initiating Member*") who proposes to make a Transfer of Common Units to a Person who is not a Permitted Transferee of such Member (other than a Transfer pursuant to Section 9.3(b)) (a "*Tag-Along Transaction*"), shall give written notice (a "*Tag-Along Notice*") to all Common Unitholders setting forth the purchase price and the terms and conditions of the Tag-Along Transaction.

Thereafter, each Common Unitholder shall have the right, but not the obligation, to elect to participate in such Tag-Along Transaction with respect to its Common Units by delivering written notice to the Initiating Member within 20 Business Days after receipt of a Tag-Along Notice. If any such Common Unitholder elects to participate in such proposed Tag-Along Transaction (each, a "*Tagging Member*"), each Tagging Member will be entitled to participate in the Tag-Along Transaction at the same time and on the same terms as the Initiating Member; provided that, (A) each Tagging Member shall be entitled to sell up to the portion of Common Units Transferred in such Tag-Along Transaction equal to its pro rata share (based on each Tagging Member's respective Fully-Funded Percentage Interest) of all Common Units proposed to be Transferred in such Tag-Along Transaction ("*Tag Percentage*") and (B) the Initiating Member shall be entitled to sell the portion of its Common Units equal to its pro rata share (based on the Initiating Member's Fully-Funded Percentage Interest) of all of the Common Units proposed to be Transferred in such Tag-Along Transaction plus any portion of its Common Units that can be Transferred in such Tag-Along Transaction in the event any Tagging Member elects to Transfer less than its Tag Percentage.

(ii) The Tag-Along Notice shall contain a true and complete copy of any and all available documents constituting the agreement to transfer and, to the extent not set forth in the accompanying documents, shall identify the Common Units proposed to be transferred, the price offered for such Common Units, all information reasonably available to the Initiating Member regarding the person to whom such Common Units are proposed to be transferred, all other material terms and conditions of the proposed transfer and, in the case of an proposed transfer in which the consideration payable for such Common Units consists in whole or in part of consideration other than cash, such information relating to such other consideration as is reasonably available to the Initiating Member.

(iii) From the date of its receipt of the Tag-Along Notice, each Tagging Member shall have the right (a "*Tag-Along Right*"), exercisable by notice (the "*Tag-Along Response Notice*") given to the Initiating Member as follows:

(A) Each Tagging Member shall have the right to request that the Initiating Member include in the proposed transfer its Tag Percentage. To be effective, each Tagging Member's Tag-Along Response Notice under this Section 9.6(b)(iii) must be given within 20 Business Days after its receipt of the Tag-Along Notice.

(B) Each Tag-Along Response Notice shall include wire transfer instructions for payment of the purchase price for the Common Units to be sold in such Tag-Along Transaction. Each Tagging Member that exercises its Tag-Along Rights hereunder shall deliver to the Initiating Member, with its Tag-Along Response Notice, all documents required to be executed in connection with such Tag-Along Transaction. Each Member (other than the Institutional Investors) hereby makes, constitutes and appoints the Initiating Member holding the largest number of Common Units among the Initiating Members, as its true and lawful attorney in fact for it and in its name, place, and stead and for its use and benefit,

to sign, execute, certify, acknowledge, swear to, file and record any instrument that is now or may hereafter be deemed necessary by the Company in its reasonable discretion to carry out fully the provisions and the agreements, obligations and covenants of such Member in this Section 9.6(b). Each Tagging Member (other than the Institutional Investors) hereby gives such attorney in fact full power and authority to do and perform each and every act or thing whatsoever requisite or advisable to be done in connection with such Member's obligations and agreements as a Tagging Member as fully as such Member might or could do personally, and hereby ratifies and confirms all that any such attorney in fact shall lawfully do or cause to be done by virtue of the power of attorney granted hereby. The power of attorney granted pursuant hereto is a special power of attorney, coupled with an interest, and is irrevocable, and shall survive the bankruptcy, insolvency, dissolution or cessation of existence of the applicable Member.

(iv) If, at the end of the 90-day period after delivery of the Tag-Along Response Notice (which 90-day period shall be extended if any of the transactions contemplated by the Tag-Along Transaction are subject to regulatory approval until the expiration of five Business Days after all such approvals have been received, but in no event later than 120 days following receipt by the Initiating Member of the Tag-Along Response Notice), the Initiating Member has not completed the transfer of its Common Units on substantially the same terms and conditions set forth in the Tag-Along Notice, the Initiating Member shall (A) return to each Tagging Member all documents in the possession of the Initiating Member executed by the Tagging Members in connection with the proposed Tag-Along Transaction and (B) not conduct any transfer of its Common Units without again complying with this Section 9.6(b).

(v) Concurrently with the consummation of the Tag-Along Transaction, the Initiating Member shall (A) notify the Tagging Members thereof, (B) cause the total consideration for the Common Units of the Tagging Members transferred pursuant thereto to be remitted directly to the Tagging Member and (C) promptly after the consummation of the Tag-Along Transaction, furnish such other evidence of the completion and the date of completion of such transfer and the terms thereof as may be reasonably requested by the Tagging Members.

(vi) If at the termination of the Tag-Along Notice Period any other Member shall not have elected to participate in the Tag-Along Transaction, such other Member shall be deemed to have waived its rights under this Section 9.6(b) with respect to the transfer of its Common Units pursuant to such Tag-Along Transaction.

(vii) Notwithstanding anything contained in this Section 9.6(b), there shall be no liability on the part of the Initiating Member to the Tagging Members if the Tag-Along Transaction pursuant to this Section 9.6(b) is not consummated for whatever reason. Whether to effect a transfer of Common Units by the Initiating Member is in the sole and absolute discretion of the Initiating Member.

(viii) Notwithstanding anything contained in this Section 9.6(b), the rights and obligations of the other Members to participate in a Tag-Along Transaction are subject to the following conditions:

(A) upon the consummation of such Tag-Along Transaction and except as provided in Section 9.6(c), all of the Members participating therein will receive the same form of consideration;

(B) no Member participating therein shall be obligated to pay any expenses incurred in connection with any unconsummated Tag-Along Transaction, and each such Member shall be obligated to pay only its pro rata share (based on the amount of the purchase price received) of expenses incurred in connection with a consummated Tag-Along Transaction to the extent such expenses are incurred for the benefit of all such Members and are not otherwise paid by the Company or another person;

(C) a Tagging Member may not, without the written consent of such Tagging Member, be obligated with respect to (1) any representation or warranty other than (x) a representation and warranty that relates solely to such Tagging Member's title to its Common Units, and its authority and capacity to execute and deliver the subject purchase and sale agreement or (y) a representation and warranty that relates to the Company and its operations which each Member is severally making to the seller (provided, that if such Member or an Affiliate of such Member is not actively involved in the day to day operations of the Company or serving on the Board of Managers, any such representation shall be limited to such Member's knowledge), (2) any indemnity obligation beyond a pro rata portion or in excess of the gross proceeds received by a Drag-Along Member (in each case, based on the value of consideration received by such Tagging Member in the Tag-Along Transaction) of the indemnity obligations which obligate the Initiating Member and all Tagging Members and then, such indemnity obligations shall be several and not joint or (3) any other continuing obligation on such Tagging Member in favor of any other person following the Tag-Along Transaction of such Tagging Member's Common Units (other than obligations relating to representations and warranties that relate solely to such Tagging Member and not to any other Member or the indemnification obligation provided for in clause (2) above); and

(D) no Tagging Member shall be obligated to consummate such Tag-Along Transaction contemplated by the Tag-Along Notice with respect to its Common Units unless the Initiating Member consummates such Tag-Along Transaction with respect to its Common Units on the terms and conditions contemplated by the Tag-Along Notice.

(c) *Non-Accredited Investors.* If any Transfer described in Section 9.6(a) or Section 9.6(b) involves the issuance of any stock or other equity consideration in a transaction not involving a public offering and any Member otherwise entitled to receive consideration in such transaction is not an accredited investor (as defined under Rule 501 of Regulation D of

the Securities Act), then the Investor Parties may require each Member that is not an accredited investor (i) to receive solely cash in such transaction, (ii) to otherwise be cashed out (by redemption or otherwise) by the Company or any other Member immediately prior to the consummation of such transaction and/or (iii) to appoint a purchaser representative (as contemplated by Rule 506 of Regulation D of the Securities Act) selected by the Company, with the intent being that such Member that is not an accredited investor receive substantially the same value that such Member would have otherwise received had such Member been an accredited investor.

9.7 Right of First Offer.

(a) After the third anniversary of the Effective Date and prior to a Final Exit Event or an Initial Public Offering, if one or more Dragging Members proposes to effect a Drag-Along Transaction (such Dragging Member(s), individually or collectively as the case may be, the "*ROFO Initiator*"), then, prior to engaging in any discussions with any third party regarding a Drag-Along Transaction, the ROFO Initiator must comply with the remaining provisions of this Section 9.7.

(b) The ROFO Initiator first must deliver a notice to the other Common Unitholders stating its bona fide intention to effect a Drag-Along Transaction (the "*ROFO Notice*"). On or prior to the 60th day after receipt of the ROFO Notice, each Common Unitholder receiving a ROFO Notice will have the right, but not the obligation, to offer, by written notice to the ROFO Initiator and all other Common Unitholders (each Common Unitholder that makes such an offer, a "*ROFO Offeror*"), to purchase all, but not less than all, of the Common Units then held by all of the other Common Unitholders (including the ROFO Initiator), which offer shall include a cash purchase price per Common Unit (the "*ROFO Offer Price*") and other terms and conditions (the "*ROFO Offer*").

(c) The ROFO Initiator will have 180 days following the last day to make a ROFO Offer (such 180th day, the "*ROFO Consummation Deadline*") to (i) accept and consummate the ROFO Offer from the ROFO Offeror that offers the highest ROFO Offer Price or (ii) consummate a Drag-Along Transaction for consideration per Common Unit equal to at least 105% of the highest ROFO Offer Price and on other terms (taken as a whole) reasonably determined by the ROFO Initiator to be no less favorable to the ROFO Initiator than those contained in the ROFO Offer that offers the highest ROFO Offer Price.

(d) If the ROFO Initiator (i) receives one or more ROFO Offers, (ii) fails to consummate the ROFO Offer that offers the highest ROFO Offer Price prior to expiration of the ROFO Consummation Deadline and (iii) fails to consummate a Drag-Along Transaction prior to the expiration of the ROFO Consummation Deadline, then the ROFO Initiator cannot, individually or collectively, again cause a transaction that would permit any Common Unit holders to invoke the provisions of this Section 9.7 prior to the first anniversary of the ROFO Notice.

9.8 Internal Restructure.

(a) Subject to the consent of the Board of Managers in accordance with Article 5, at any time, the Company may effect an Internal Restructure on such terms as the Board of Managers in the exercise of its reasonable discretion deems advisable. Each Member agrees that it will consent to and raise no objections to an Internal Restructure; provided that (i) the Internal Restructure is undertaken in a manner that results in the Members continuing to have substantially the same direct or indirect ownership of the Company's assets in place prior to the Internal Restructure, (ii) the Internal Restructure preserves the relative economic interests, preferences, priorities and designations of the Members in the Company or any entity that succeeds to the Company in such Internal Restructure transaction and (iii) such Member determines, based on written advice of counsel, that the Internal Restructure does not have a reasonable risk of having a material adverse legal, regulatory, tax or accounting effect on such Member. Each Member hereby agrees that it will execute and deliver all agreements, instruments and documents as are required, in the reasonable judgment of the Board of Managers, to be executed by such Member in order to consummate the Internal Restructure while continuing in effect, to the extent consistent with such Internal Restructure, the terms and provisions of this Agreement, including those provisions granting the Board of Managers authority to manage the affairs of the Company, granting certain persons the right to nominate and cause the election of Managers, governing transfers of interests in the Company or other equity securities and indemnification.

(b) The Members acknowledge that an Internal Restructure may be undertaken in connection with other events, such as an Initial Public Offering or an acquisition of another business or entity and, if so determined by the Board of Managers, such Internal Restructure shall be deemed completed immediately before any such event.

(c) The Members acknowledge that, to engage in an Initial Public Offering, it may be necessary or advisable for the Company to merge or convert into a Delaware corporation or such other entity as may be determined by the Board of Managers (a "*Conversion*"). Accordingly, if the Board of Managers determines it to be in the best interests of the Company to engage in an Initial Public Offering and to effect a Conversion, the Members agree that the Company's capital structure shall be restructured in the manner described in this Section 9.8 and the Members shall vote and take all other action necessary in order to effect such Conversion. In connection with a Conversion, all Membership Interests of the Company (the "*Old Interests*") will be exchanged for common stock of the surviving corporation (the "*Conversion Consideration*"), with unvested Management Incentive Units being exchanged for restricted common stock of the surviving corporation that is subject to vesting. In determining the portion of the Conversion Consideration to be exchanged for the Old Interests, the Company shall determine what portion of the Conversion Consideration would have been distributed among all of the holders of the Old Interests if the Company's sole asset consisted of the Conversion Consideration and the Company distributed the Conversion Consideration in the same manner distributions would have been made in a complete liquidation of the Company taking into account the various rights, preferences and designations governing the Old Interests (which rights, preferences and designations are set forth in this Agreement, each as they may exist before the Conversion). Once the Company determines the portion of the Conversion Consideration that would have been distributed to each class or series of Old Interests if the Company had been liquidated immediately before the Conversion, the Board of

Managers will then determine the exchange ratio of the Old Interest into common shares of the surviving corporation.

(d) Upon the consummation of an Internal Restructure, the surviving entity or entities shall assume or succeed to all of the outstanding debt and other liabilities and obligations of the Company. To the extent practicable, the governing instruments of the surviving entity shall incorporate the governance provisions of this Agreement. All Members shall take such actions as may be reasonably required and otherwise cooperate in good faith with the Company in connection with consummating an Internal Restructure including a Conversion including voting for or consenting thereto.

(e) In connection with an Internal Restructure for purposes of an initial public offering, if any Institutional Investor or its limited partners or investors has a structure involving ownership of all or a portion of its interests in the Company, directly or indirectly, through one or more single purpose entities (a "*Blocker Corporation*"), at the request of any such Institutional Investor, the Company will use commercially reasonable efforts to merge any such Blocker Corporation into the entity that will be the registrant in an initial public offering in a tax-free reorganization (if such registrant is taxed as an association and not as a partnership) or otherwise structure the transaction so that the Blocker Corporation is not subject to a level of corporate tax on an initial public offering or subsequent dividend payments or sales of stock, so long as the foregoing could not reasonably be expected to result in any costs or liabilities that are not indemnified or reimbursed by the stockholders or Affiliates of the Blocker Corporation or other adverse effects (other than de minimis adverse effects) to the Company or any of the Members (other than to the Blocker Corporation).

ARTICLE 10
RELATIONSHIP OF MEMBERS, MANAGERS, OFFICERS, THE COMPANY AND OTHERS

10.1 Duties of Members, Managers and Officers.

(a) *Members.* To the fullest extent permitted by applicable Law and notwithstanding any provision of this Agreement to the contrary, no Member, in its capacity as a Member, shall have any duty, fiduciary or otherwise, to the Company, any other Member, any Manager or any other Person in connection with the business and affairs of the Company or any consent or approval given or withheld pursuant to this Agreement, other than the implied contractual covenant of good faith and fair dealing implied by the Act. Notwithstanding anything in this Agreement to the contrary, each of the Company and the Members acknowledges and agrees that each Member, in its capacity as a Member, may decide or determine any matter subject to such Member's approval pursuant to any provision of this Agreement in such Member's sole and absolute discretion, and in making such decision or determination such Member shall have no duty, fiduciary or otherwise, to the Company, any other Member, any Manager or any other Person, it being the intent of all Members that each Member, in its capacity as a Member, has the right to make such determination solely on the basis of such Member's own interests without the need to give any consideration to any other interests or factors whatsoever. Each of the Company and each Member hereby agrees that any claims against, actions, rights to sue, other remedies or other recourse to or against the

Members or any of their respective Affiliates for or in connection with any such decision or determination in each case whether arising in common law or equity or created by rule of law, statute, constitution, contract (including this Agreement) or otherwise, are in each case expressly released and waived by the Company and each Member, to the fullest extent permitted by law, as a condition of, and as part of the consideration for, the execution of this Agreement and any related agreement, and the incurrence by the Members of the obligations provided in this Agreement and any related agreement, unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of such decision or determination, and taking into account the acknowledgments and agreements set forth in this Agreement, such Member engaged in a bad faith violation of the implied contractual covenant of good faith and fair dealing.

(b) *Member Managers.* To the fullest extent permitted by applicable Law and notwithstanding any provision of this Agreement to the contrary, each of the Managers designated by an Institutional Investor (a "*Member Manager*"), in such Person's capacity as a Manager, shall serve in such capacity to represent the interests of the Member or group of Members that designated such Manager and shall be entitled to consider only such interests (including the interests of the Member or group of Members that designated such Manager) and factors specified by the Member or group of Members that designated such Manager, and shall have no fiduciary or other duties to the Company, any other Member, any other Manager or any other Person in connection with the business and affairs of the Company or any consent or approval given or withheld pursuant to this Agreement, other than the implied contractual covenant of good faith and fair dealing.

(c) *Company Managers.* To the fullest extent permitted by applicable Law and notwithstanding any provision of this Agreement to the contrary, each of the Managers other than any Member Manager (a "*Company Manager*"), in such Person's capacity as a Manager, shall have no fiduciary or other duties to the Company, any Member, any other Manager or any other Person in connection with the business and affairs of the Company or any consent or approval given or withheld pursuant to this Agreement, other than the implied contractual covenant of good faith and fair dealing.

(d) *Officers.* To the fullest extent permitted by applicable law and notwithstanding any provision of this Agreement to the contrary, each of the Officers, in such Person's capacity as an Officer, shall have the same fiduciary duties that an Officer of the Company would have if the Company were a corporation organized under the laws of the State of Delaware, and the Company and the Members shall have the same rights and remedies in respect of such duties as if the Company were a corporation organized under the Laws of the State of Delaware and the Members were its stockholders.

10.2 Liability and Indemnification.

(a) *Liability.* To the maximum extent permitted by applicable Law, no Member Covered Person or Manager Covered Person will be liable to the Company, any Member or any other Person for losses sustained or liabilities incurred as a result of any act or omission, including any breach of a duty (fiduciary or otherwise), that such Covered Person may have taken or omitted with respect to the Company, such other Member, or such other Person,

unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of such act or omission, and taking into account the acknowledgments and agreements set forth in this Agreement, such Member Covered Person or Manager Covered Person engaged in a bad faith violation of the implied contractual covenant of good faith and fair dealing.

(b) *Member Covered Person and Manager Covered Person Indemnification.* Each Member Covered Person and each Manager Covered Person shall be indemnified and held harmless by the Company (but only to the extent of the Company's assets), to the fullest extent permitted by applicable Law, from and against any and all losses, liabilities and expenses (including taxes; penalties; judgments; fines; amounts paid or to be paid in settlement; costs of investigation and preparations; and reasonable fees, expenses and disbursements of attorneys (as incurred), whether or not the dispute or proceeding involves the Company or any Manager or Member) incurred or suffered by any such Member Covered Person or Manager Covered Person, as applicable, in connection with the activities of the Company or its Subsidiaries; provided that, such Member Covered Person or Manager Covered Person, as applicable, shall not be so indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which such Member Covered Person or Manager Covered Person, as applicable, is seeking indemnification or seeking to be held harmless hereunder, and taking into account the acknowledgments and agreements set forth in this Agreement, such Member Covered Person or Manager Covered Person, as applicable, engaged in a bad faith violation of the implied contractual covenant of good faith and fair dealing implied by the Act. A Member Covered Person or Manager Covered Person shall not be denied indemnification in whole or in part under this Section 10.2(b) because such Member Covered Person or Manager Covered Person had an interest in the transaction with respect to which the indemnification applies if the transaction was otherwise permitted by the terms of this Agreement.

(c) *Officer Covered Person Indemnification.* Each Officer Covered Person shall be indemnified and held harmless by the Company (but only to the extent of the Company's assets), to the fullest extent permitted by applicable Law, as if the Company were a corporation organized under the laws of the State of Delaware and to the fullest extent permitted under Section 145 of the General Corporation Law of the State of Delaware as in effect on the Effective Date (but including any expansion of rights to indemnification thereunder from and after the Effective Date), from and against any and all losses, liabilities and expenses (including taxes; penalties; judgments; fines; amounts paid or to be paid in settlement; costs of investigation and preparations; and reasonable fees, expenses and disbursements of attorneys (as incurred), whether or not the dispute or proceeding involves the Company or any Manager, Member or Officer) incurred or suffered by any such Officer Covered Person in connection with the activities of the Company or its Subsidiaries. An Officer Covered Person shall not be denied indemnification in whole or in part under this Section 10.2(c) because such Officer Covered Person had an interest in the transaction with respect to which the indemnification applies if the transaction was otherwise permitted by the terms of this Agreement.

(d) *Good Faith Reliance.* A Covered Person shall be fully protected in relying in good faith, and shall incur no liability in acting or refraining from acting, upon the records of the Company and upon such resolutions, certificates, instruments, information, opinions,

reports, statements, notices, requests, consents, orders, bonds, debentures, signatures or writings reasonably believed by it to be genuine and presented to the Company, and may rely on a certificate signed by an officer, agent or representative of, any Person as to matters the Covered Person reasonably believes are within the professional or expert competence of such Person and who has been selected with reasonable care by or on behalf of the Company, including such documents, certificates, information, opinions, reports or statements as to the value and amount of the assets, liabilities, income, loss or any other facts pertinent to the existence and amount of assets from which distributions to Members might properly be paid, in each case, unless (i) in the case of a Member Covered Person or a Manager Covered Person, there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of such reliance, action or inaction, such Member Covered Person or Manager Covered Person acted in bad faith, or (ii) in the case of an Officer Covered Person, there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of such reliance, action or inaction, such Officer Covered Person acted in bad faith, engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such Officer Covered Person's conduct was unlawful.

(e) *Advancement of Expenses.* The Company shall advance to a Covered Person the reasonable, documented expenses incurred by such Covered Person for which such Covered Person could reasonably be expected to be entitled to indemnification under this Agreement in defending any civil, criminal, administrative or investigative action, suit or proceeding in advance of the final disposition of such action, suit or proceeding upon receipt by the Company of the written affirmation of such Covered Person of its good faith belief that it is entitled to indemnification hereunder and an undertaking by such Covered Person to repay any such advances if it is subsequently determined that such Covered Person is not entitled to be indemnified hereunder.

(f) *Priority of Certain Third-Party Indemnification Rights.* The Company and each of the Members hereby acknowledges that certain of the Covered Persons ("*Third-Party Indemnitees*") have certain rights to indemnification, advancement of expenses or insurance provided by each Institutional Member or certain of its Affiliates (collectively, the "*Third-Party Indemnitors*"). The Company hereby agrees, and the Members hereby acknowledge, that: (i) to the extent legally permitted and as required by the terms of this Agreement and the Certificate (or by the terms of any other agreement between the Company and a Third-Party Indemnitee), (A) the Company is the indemnitor of first resort (i.e., its obligations to each Third-Party Indemnitee are primary and any obligation of the Third-Party Indemnitors to advance expenses or to provide indemnification for the same expenses or liabilities incurred by any Third-Party Indemnitee are secondary) and (B) the Company shall be required to advance the full amount of expenses incurred by any Third-Party Indemnitee and shall be liable for the full amount of all expenses, judgments, penalties, fines and amounts paid in settlement, without regard to any rights that a Third-Party Indemnitee may have against the Third-Party Indemnitors and (ii) the Company irrevocably waives, relinquishes and releases the Third-Party Indemnitors from any and all claims for contribution, subrogation or any other recovery of any kind in respect of any of the matters described in clause (i) of this sentence for which any Third-Party Indemnitee has received indemnification or advancement from the Company. The Company further agrees that no advancement or payment by the Third-Party Indemnitors

on behalf of any Third-Party Indemnitee with respect to any claim for which an Third-Party Indemnitee has sought indemnification from the Company shall affect the foregoing and that the Third-Party Indemnitors shall have a right of contribution and/or be subrogated to the extent of such advancement or payment to all of the rights of recovery of such Third-Party Indemnitee against the Company. The Company and each Member agree that the Third-Party Indemnitors are express third party beneficiaries of the terms of this Section 10.2(e).

(g) *Indemnification Rights Cumulative.* The rights to indemnification and advancement of expenses provided by this Section 10.2 shall be in addition to any other rights to which a Covered Person may be entitled under any agreement, as a matter of Law or otherwise, both as to actions in such Covered Person's capacity as a Covered Person hereunder and as to actions in any other capacity, and shall continue as to a Covered Person who has ceased to serve in such capacity as a Covered Person and shall inure to the benefit of the heirs, successors, assigns and administrators of such Covered Person.

(h) *Multiple Rights to Indemnification.* Any Covered Person shall be entitled to be indemnified for any loss, liability or expense (including taxes; penalties; judgments; fines; amounts paid or to be paid in settlement; costs of investigation and preparations suffered by any such Person; and fees, expenses, and disbursements of attorneys, whether or not the dispute or proceeding involves the Company or any Manager or Member) to the greatest extent that such Covered Person is entitled to indemnification for the capacity in which such Covered Person served with respect to such matters under this Agreement.

10.3 Procedure for Indemnification; Company Obligations; Indemnification Rights.

(a) *Written Request for Indemnification.* Any indemnification or advance of expenses under this Article 10 shall be made only against a written request therefore submitted by or on behalf of the Person seeking such indemnification or advance. All expenses (including reasonable attorneys' fees) incurred by such Person in connection with successfully establishing such Person's right to indemnification or advance of expenses under this Article 10, in whole or in part, shall also be indemnified by the Company.

(b) *Consultation with Legal Counsel.* Each Covered Person may consult with outside legal counsel approved by the Company, which approval shall not be unreasonably withheld, and any action or omission taken or suffered reasonably and in good faith in reliance and accordance with the written opinion or advice of such counsel will be conclusive evidence that such action or omission was not a violation of such Covered Person's implied covenant of good faith and fair dealing implied by the Act.

(c) *No Presumption.* Unless there is a specific finding that (i) in the case of a Member Covered Person or Manager Covered Person, such Covered Person's actions constituted a bad faith violation of such Covered Person's implied covenant of good faith and fair dealing or (ii) in the case of an Officer Covered Person, such Officer Covered Person's actions constituted a violation of Section 145 of the General Corporation Law of the State of Delaware (or, in any such case, where any such finding is an essential element of a judgment or order), the termination of any action, suit or proceeding by judgment, order or settlement, or

upon a plea of nolo contendere or its equivalent, will not, of itself, create a presumption for the purposes of this Section 10.3(c) as to whether or not (A) in the case of such Member Covered Person or Manager Covered Person, as applicable, committed a violation of any such implied covenant of good faith and fair dealing or (B) in the case of such Officer Covered Person, committed a violation of Section 145 of the General Corporation Law of the State of Delaware.

(d) *Company Obligations.* The obligations of the Company to the Covered Persons provided in this Agreement or arising under Law are solely the obligations of the Company, and no personal liability whatsoever shall attach to, or be incurred by, any Covered Person or any Member for such obligations, to the fullest extent permitted by Law. Where the foregoing provides that no personal liability shall attach to or be incurred by a Covered Person, any claims against or recourse to such Covered Person for or in connection with such liability, whether arising in common law or equity or created by rule of law, statute, constitution, contract or otherwise, are expressly released and waived under this Agreement, to the fullest extent permitted by Law, as a condition of, and as part of the consideration for, the execution of this Agreement and any related agreement, and the incurring by the Company of the obligations provided in such agreements.

(e) *Successors, Assigns, Etc.* The provisions of this Article 10 will inure to the benefit of the successors, assigns, heirs, and personal representatives of the Indemnified Persons.

(f) *Notification.* The Board will promptly notify the Members of any payment made by the Company to any Covered Person in respect of indemnification pursuant to this Article 7 in connection with any settlement, judgment, order or plea of nolo contendere made by such Covered Person.

10.4 Amendment, Modification or Repeal.

Any amendment, modification or repeal of any provision of this Article 10 shall be prospective only and shall not in any way affect the limitations on the liability or indemnification of any Covered Person under such provisions as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted without the written consent of such Covered Person.

ARTICLE 11 .

MISCELLANEOUS

11.1 Notices.

Any and all notices, consents or demands permitted or required to be made under this Agreement shall be in writing, signed by the Person giving such notice or demand and shall be delivered solely (i) by hand (with signed confirmation of receipt), (ii) by overnight mail (with signed confirmation of receipt), or (iii) by registered or certified mail, return receipt requested. All such notices or demands shall be deemed delivered, as applicable: (a) on the date of the personal delivery; (b) on the next Business Day for overnight mail; or (c) on the date of the signed receipt for registered or certified mail. Such notices or communications to be sent to a

Member shall be given to such Member at the address given for such Member on Exhibit A-1. Such notices or communications to be sent to the Company shall be given at the following address: 1800 Bering Drive, Suite 540, Houston, Texas 77057. Any party hereto may designate any other address in substitution for the foregoing address to which such notice shall be given by five days' notice duly given hereunder to the other parties.

11.2 Governing Law and Venue.

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware, without giving effect to any Delaware choice of law principles that might indicate the applicability of the laws of any other jurisdiction. THE MEMBERS CONSENT TO THE EXCLUSIVE PERSONAL JURISDICTION OF THE CHANCERY COURT OF THE STATE OF DELAWARE.

11.3 Waiver of Action for Partition.

Each of the Members irrevocably waives during the term of the Company any right that such Member may have to maintain an action for partition with respect to the property of the Company.

11.4 Successors and Assigns.

This Agreement shall be binding upon and shall inure to the benefit of the Members and their respective permitted heirs, legal representatives, successors and assigns.

11.5 Amendment.

(a) The Board of Managers may amend any provision of this Agreement or the Certificate, and execute, swear to, acknowledge, deliver, file and record whatever documents may be required, in connection therewith, to reflect:

(i) a change in the name of the Company, in the registered office or registered agent of the Company or in the location of the principal place of business of the Company;

(ii) the admission or substitution of Members as provided in this Agreement or a change in their Capital Commitments as contemplated by this Agreement;

(iii) a change that the Board of Managers has determined is reasonable and necessary or appropriate to qualify or register, or continue the qualification or registration of, the Company as a limited liability company (or an entity in which the Members have limited liability) under the laws of any state or a change that is necessary or advisable in the opinion of the Board of Managers to ensure that the Company will not be treated as an association taxable as a corporation for federal income tax purposes; or

(iv) a change that the Board of Managers has determined is reasonable and necessary or appropriate in order to achieve the business, economic and tax objectives of the Company or in order to conform to applicable State law, custom or practice.

(b) If an Institutional Investor notifies the Company that the provisions of this Agreement should be amended to preserve the qualification of such Investor as a "venture capital operating company" (as defined by the regulations issued by the United States Department of Labor at Section 2510.3-101 of Part 2510 of Chapter XXV, Title 29 of the United States Code of Federal Regulations (or any similar successor statute)) or otherwise to ensure that the assets of such Institutional Investor are not "plan assets" for purposes of the Employee Retirement Income Security Act of 1974, as amended (or any similar successor statute), then the Company shall amend this agreement with an instrument executed by the Company and such Institutional Investor without the consent of any other party hereto (a "*VCOC Amendment*") as long as such amendment will not adversely affect the rights of any other Member.

(c) Other than amendments adopted pursuant to Section 11.5(a) and Section 11.5(b), this Agreement and the Certificate may be amended only by approval of the Board of Managers and Supermajority Member Approval; provided that, any amendment to reflect the admission or withdrawal of one or more Members may be made without the necessity of any further agreement or vote pursuant to this Section 11.5; provided further that, any amendment which disproportionately and adversely affects the rights of any Members, in their capacity as holders of a specific series or class of Interests, other than in a de minimis, non-economic respect, compared to other Members in their capacities as the holders of the same or any other series or class of Interests shall also require the prior written consent of each of the Members so disproportionately and adversely affected; and provided further that any amendment that either increases the Capital Commitment of a Member or waives the limited liability of a Member shall also require the prior written consent of such Member; and provided further that any amendment to Sections 1.9 [Alternative Investment Structure], Section 3.7 [Non-Voting Interests], Section 5.2(g) [Board Observers], Section 6.4 [Area of Mutual Interest], Section 7.5 [Confidentiality] (only with respect to matters therein that affect solely Wells Fargo or Union Bank), Section 9.3(b) [Potentially Restricted Member Transfer Right] and this Section 11.5(c) (only with respect to matters therein that affect solely Wells Fargo or Union Bank) shall also require the prior written consent of Wells Fargo and Union Bank. For the avoidance of doubt, (i) any such amendment made in connection with the authorization or issuance by the Company of additional Interests having such rights, designations and preferences (including with respect to distributions) ranking senior or junior to, or *pari passu* with, Common Units, Management Incentive Units or any other series or class of Interests shall require only the approval of the Board of Managers and Supermajority Investor Approval and that such amendment shall not be deemed an alteration or change to the rights, obligations, powers or preferences of any series or class of Interests and (ii) any such amendment which changes the relative proportions of any distributions to be received by the Common Unitholders (on the one hand) and the Management Incentive Members (on the other hand) in any Tier set forth in Section 4.2(a) shall also require the prior written consent of the Management Incentive Members holding a majority of the Management Incentive Units.

11.6 Counterparts.

This Agreement may be executed in multiple counterparts that, when taken together, shall constitute one instrument.

11.7 No Waiver.

The failure of any Member to insist upon strict performance of a covenant hereunder or of any obligation hereunder, irrespective of the length of time for which such failure continues, shall not constitute a waiver of such Member's right to demand strict compliance in the future. No consent or waiver, express or implied, to or of any breach or default in the performance of any obligation hereunder shall constitute a consent or waiver to or of any other breach or default in the performance of the same or any other obligation hereunder.

11.8 Execution in Writing.

A facsimile, telex or similar transmission by a Member or Manager, or a photographic, photostatic, facsimile or similar reproduction of a writing executed by a Member or Manager, shall be treated as an execution in writing for purposes of this Agreement.

11.9 Representation by Counsel.

(a) The Members acknowledge and agree (i) that Morgan, Lewis & Bockius LLP ("*MLB*") (A) has represented Contaro in connection with the negotiation, execution and delivery of this Agreement and all other agreements contemplated by this Agreement and (B) has not represented the Company or any Member other than Contaro and (ii) in no event shall an attorney-client relationship be deemed to exist between MLB, on the one hand, and the Members (other than Contaro) or any of their respective Affiliates, or the Company, on the other hand, in respect of MLB's representation as described in clauses (i)(A) and (i)(B) above.

(b) The Members acknowledge and agree (i) that Vinson & Elkins LLP ("*VE*") (A) has represented the Sageview Parties in connection with the negotiation, execution and delivery of this Agreement and all other agreements contemplated by this Agreement and (B) has not represented the Company or any Member other than the Sageview Parties and (ii) in no event shall an attorney-client relationship be deemed to exist between VE, on the one hand, and the Members (other than the Sageview Parties) or any of their respective Affiliates, or the Company, on the other hand, in respect of VE's representation as described in clauses (i)(A) and (i)(B) above.

(c) The Members acknowledge and agree (i) that Baker Botts L.L.P. ("*BB*") (A) has represented the Jefferies Parties in connection with the negotiation, execution and delivery of this Agreement and all other agreements contemplated by this Agreement and (B) has not represented the Company (except with respect to the Development Agreement) or any Member other than the Jefferies Parties and (ii) in no event shall an attorney-client relationship be deemed to exist between BB, on the one hand, and the Members (other than the Jefferies Parties) or any of their respective Affiliates, or the Company (except with respect to the Development Agreement), on the other hand, in respect of BB's representation as described in clauses (i)(A) and (i)(B) above.

(d) The Members acknowledge and agree (i) that Doherty & Doherty LLP ("*DD*") (A) has represented Management in connection with the negotiation, execution and delivery of this Agreement and all other agreements contemplated by this Agreement and (B) has not represented the Company or any Member other than Management and (ii) in no event shall an

attorney-client relationship be deemed to exist between DD, on the one hand, and the Members (other than Management) or any of their respective Affiliates, or the Company, on the other hand, in respect of DD's representation as described in clauses (i)(A) and (i)(B) above.

11.10 Entire Agreement.

This Agreement, the exhibits hereto and the Transaction Documents, together with the certificates, documents, instruments and writings delivered pursuant thereto, constitute the entire agreement and understanding of the parties hereto in respect of its subject matters and supersedes all prior understandings, agreements or representations by or among such parties, written or oral, to the extent they relate in any way to the subject matter hereof and thereof. There are no representations as to the administration of this Agreement that are not contained herein.

[The remainder of this page is intentionally blank]

IN WITNESS WHEREOF, the Company has executed this Agreement as of the date first above set forth.

THE COMPANY:

EXARO ENERGY III LLC

By: /s/ Christopher L. Beato
Name: Christopher L. Beato
Title: President and Chief Executive Officer

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

CONTARO COMPANY
By:/s/ Sergio Castro
Name: Sergio Castro
Title: CFO

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

SAGEVIEW CAPITAL PARTNERS (A), L.P.
By: Sageview Capital GenPar, Ltd.
its General Partner
By: /s/ Edward A. Gilhuly
Name: Edward A. Gilhuly
Title: Director

SAGEVIEW CAPITAL PARTNERS (B), L.P.

By: Sageview Capital GenPar, Ltd.
its General Partner

By: /s/ Edward A. Gilhuly
Name: Edward A. Gilhuly
Title: Director

SAGEVIEW ENERGY PARTNERS (C) INVESTMENTS, L.P.

Sageview Capital GenPar, L.P.

By: Sageview Capital MGP, LLC
its General Partner

By: /s/ Edward A. Gilhuly
Name: Edward A. Gilhuly
Title: Director

SAGEVIEW CAPITAL GENPAR, L.P.

By: Sageview Capital MGP, LLC
its General Partner

By: /s/ Edward A. Gilhuly
Name: Edward A. Gilhuly
Title: Director

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

JEFFERIES CAPITAL PARTNERS IV L.P.
JEFFERIES EMPLOYEE PARTNERS IV LLC
JCP PARTNERS IV LLC
By: Jefferies Capital Partners IV LLC
Manager
By: /s/ James Luikart
Name: James Luikart
Title: Managing Member

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

UNIONBANCAL EQUITIES, INC.
By: /s/ Derrick Pan
Name: Derrick Pan
Title: Vice President

By: /s/ Margaret Elower
Name: Margaret Elower
Title: Vice President

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

WELLS FARGO CENTRAL PACIFIC HOLDINGS, INC.
By: /s/ Gilbert Shen

Name: Gilbert Shen
Title: Vice President

IN WITNESS WHEREOF, the undersigned Person has executed this Agreement as of the date first above set forth for purposes of agreeing solely to the obligations set forth in Section 6.4.

WELLS FARGO ENERGY CAPITAL, INC.
By: /s/ Bryan McDavid
Name: Bryan McDavid
Title: Director

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

BEATO FAMILY 2008 TRUST

/s/ Christopher L. Beato
Name: Christopher L. Beato

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

CHRISTOPHER L. BEATO
/s/ Christopher L. Beato

The undersigned spouse of the above signed Member is executing this Agreement in order to acknowledge its terms and conditions, is aware of, understands and consents to the provisions of this Agreement, each other Transaction Document that has been or will be executed by such Member or is otherwise binding on such Member and its and such other agreements' binding effect upon any community property interest or marital settlement awards he or she may now or hereafter own or receive, and hereby agrees that the termination of his or her marital relationship with such Member for any reason shall not have the effect of removing any Interests subject to this Agreement from the coverage thereof and that his or her awareness, understanding, consent and agreement is evidenced by his or her signature below.

ANNE BEATO

/ s/ Anne Beato

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Section 3.6(a) are true and correct as of the date of this execution.

JOHN P. ATWOOD
/s/ John P.
Atwood

The undersigned spouse of the above signed Member is executing this Agreement in order to acknowledge its terms and conditions, is aware of, understands and consents to the provisions of this Agreement, each other Transaction Document that has been or will be executed by such Member or is otherwise binding on such Member and its and such other agreements' binding effect upon any community property interest or marital settlement awards he or she may now or hereafter own or receive, and hereby agrees that the termination of his or her marital relationship with such Member for any reason shall not have the effect of removing any Interests subject to this Agreement from the coverage thereof and that his or her awareness, understanding, consent and agreement is evidenced by his or her signature below.

HOLLY ATWOOD
/s/ Holly Atwood

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Sections 3.6(a) and (b) are true and correct as of the date of this execution.

SCOTT R. CLARK
/s/ Scott R. Clark

The undersigned spouse of the above signed Member is executing this Agreement in order to acknowledge its terms and conditions, is aware of, understands and consents to the provisions of this Agreement, each other Transaction Document that has been or will be executed by such Member or is otherwise binding on such Member and its and such other agreements' binding effect upon any community property interest or marital settlement awards he or she may now or hereafter own or receive, and hereby agrees that the termination of his or her marital relationship with such Member for any reason shall not have the effect of removing any Interests subject to this Agreement from the coverage thereof and that his or her awareness, understanding, consent and agreement is evidenced by his or her signature below.

IONA MICHELLE CLARK
/s/ Iona Michelle Clark

IN WITNESS WHEREOF, the undersigned Member has executed this Agreement as of the date first above set forth and hereby represents and warrants to the Company and Members that the representations contained in Sections 3.6(a) and (b) are true and correct as of the date of this execution.

BRANCH J. RUSSELL
/s/ Branch J. Russell

The undersigned spouse of the above signed Member is executing this Agreement in order to acknowledge its terms and conditions, is aware of, understands and consents to the provisions of this Agreement, each other Transaction Document that has been or will be executed by such Member or is otherwise binding on such Member and its and such other agreements' binding effect upon any community property interest or marital settlement awards he or she may now or hereafter own or receive, and hereby agrees that the termination of his or her marital relationship with such Member for any reason shall not have the effect of removing any Interests subject to this Agreement from the coverage thereof and that his or her awareness, understanding, consent and agreement is evidenced by his or her signature below.

JOYCE RUSSELL
/s/ Joyce Russell

EXHIBIT A-1
NAMES, ADDRESSES, CAPITAL CONTRIBUTIONS,
CAPITAL COMMITMENTS AND COMMON UNITS OF THE MEMBERS

Name and Address of Member	Existing Capital Contributions	Remaining Capital Commitment	Total Capital Commitment	Existing Common Units	Common Units (assuming fully funded Total Capital Commitment)
Contaro 3700 Buffalo Speedway, Suite 960 Houston, TX 77098	$33,750,000.00	$ 33,750,000.00	$ 67,500,000.00	33,750,000	67,500,000
Sageview A 55 Railroad Avenue, 1st Floor Greenwich, CT 06830	17,800,000.00	17,800,000.00	35,600,000.00	17,800,000	35,600,000
Sageview B 55 Railroad Avenue, 1st Floor Greenwich, CT 06830	8,000,000.00	8,000,000.00	16,000,000.00	8,000,000	16,000,000
Sageview C 55 Railroad Avenue, 1st Floor Greenwich, CT 06830	1,700,000.00	1,700,000.00	3,400,000.00	1,700,000	3,400,000
Sageview GenPar 55 Railroad Avenue, 1st Floor Greenwich, CT 06830	1,250,000.00	1,250,000.00	2,500,000.00	1,250,000	2,500,000
Jefferies Capital Partners IV L.P. 520 Madison Avenue New York, NY 10022	15,194,316.66	15,194,316.68	30,388,633.34	15,194,317	30,388,634
Jefferies Employee Partners IV LLC 520 Madison Avenue New York, NY 10022	1,750,029.17	1,750,029.16	3,500,058.33	1,750,029	3,500,058
JCP Partners IV LLC 520 Madison Avenue New York, NY 10022	555,654.17	555,654.16	1,111,308.33	555,654	1,111,308
Union Bank 445 South Figueroa Street, 21st Floor Los Angeles, CA 90071	5,000,000.00	5,000,000.00	10,000,000.00	5,000,000	10,000,000
Wells Fargo 600 California St, 20th Floor San Francisco, CA 94108	5,000,000.00	5,000,000.00	10,000,000.00	5,000,000	10,000,000
Beato Family Trust 1800 Bering Drive, Suite 540 Houston, TX 77057	1,200,000.00	—	1,200,000.00	1,200,000	1,200,000
Atwood 6159 Valley Forge Houston, TX 77057	625,000.00	—	625,000.00	625,000	625,000
Clark 8185 Moore Street Arvada, CO 80005	937,500.00	—	937,500.00	937,500	937,500
Russell 43 West Wedgwood Glen The Woodlands, Texas 77381	60,000.00	—	60,000.00	60,000	60,000
TOTAL	**$ 92,822,500.00**	**$ 90,000,000.00**	**$ 182,822,500.00**	**92,822,500**	**182,822,500**

EXHIBIT A-2
INITIAL MANAGEMENT INCENTIVE UNIT GRANTS AT THE EFFECTIVE DATE

Management Incentive Member	Management Incentive Units
Christopher L. Beato 1800 Bering Drive, Suite 540 Houston, TX 77057	243,750
John P. Atwood 6159 Valley Forge Houston, TX 77057	162,500
Scott R. Clark 8185 Moore Street Arvada, CO 80005	243,750

EXHIBIT B
MANAGEMENT INCENTIVE PLAN

This Management Incentive Plan (the "*Plan*") has been adopted by all of the Members of Exaro Energy III LLC, a Delaware limited liability company (the "*Company*"), and has been made a part of the Second Amended and Restated Limited Liability Company Agreement of the Company dated effective as of February 1, 2013 (as amended or restated from time to time, the "*Company Agreement*"). Capitalized terms used but not defined herein will have the meaning ascribed to them in the Company Agreement.

1. Purpose. The Plan is intended to provide incentives to Eligible Employees (as defined in Section 3 below) by providing such persons with awards of units representing management incentive interests in the Company (each, a "*Management Incentive Unit*" and collectively, the "*Management Incentive Units*"), the rights, preferences, limitations, obligations and liabilities of which are governed by the Company Agreement, this Plan, any Employment Agreement and a letter agreement, a form of which is attached as Annex A hereto, delivered at or about the time such Management Incentive Units are granted to such Management Incentive Member (each, an "*Award Letter*"). If the terms of this Plan, any Employment Agreement or any Award Letter conflict in any way with the terms of the Company Agreement, the terms of the Company Agreement will govern and if the terms of any Employment Agreement or any Award Letter conflict in any way with the terms of this Plan, the terms of this Plan will govern. The terms of this Plan, any Employment Agreement or any Award Letter will not be deemed in conflict or inconsistent with the provisions of the Company Agreement merely because they impose greater or additional restrictions, obligations or duties.

2. Administration of the Plan. The Plan will be administered by the Board of Managers of the Company ("*Board of Managers*") pursuant to the express terms hereof and of the Company Agreement. Subject to the other terms of this Plan, the Board of Managers will have the sole authority to determine the following: (i) to whom, from among the class of individuals eligible under Section 3 of this Plan to receive the Management Incentive Units that may be awarded ("*Eligible Employees*"); (ii) the number of Management Incentive Units to be awarded; (iii) the time or times at which the Management Incentive Units will be awarded; (iv) the Deemed Exercise Price of the Management Incentive Units (if other than $0); (v) the time or times when the Management Incentive Units will become vested and the duration of the vesting period (if applicable); (vi) whether restrictions such as repurchase options (in addition to those in the Company Agreement) are to be imposed on the Management Incentive Units and the nature of such restrictions, if any; (vii) any and all other terms and conditions with respect to awards of Management Incentive Units not inconsistent with the Company Agreement or this Plan; and (viii) to interpret the Plan and prescribe and rescind rules and regulations relating to it. The interpretation and construction by the Board of Managers of any provisions of the Plan, any Employment Agreement, any Award Letter and the Company Agreement with respect to any Management Incentive Unit awarded under this Plan will be final. The Board of Managers may from time to time adopt such rules and regulations for carrying out the Plan as it may deem advisable so long as they are consistent with the foregoing. No member of the Board of Managers will be liable to the Company, any Member thereof or any Eligible Employee for any

action or determination made in good faith with respect to the Plan or any Management Incentive Unit awarded under it.

3. Eligible Employees. Management Incentive Units may be awarded to any Manager, employee or independent contractor of the Company or its Subsidiaries or any employee of the Management Company who provides services to the Company and its Subsidiaries (each, an "*Eligible Employee*") or any Affiliate of an Eligible Employee (an "*Eligible Employee Affiliate*"). The Managing Member may take into consideration a recipient's individual circumstances in determining whether to recommend to the Board of Managers an award of a Management Incentive Unit. The awarding of any Management Incentive Units to any individual will neither entitle such person to, nor disqualify such person from, employment with the Company or any of its Affiliates or participation in any other grant of Management Incentive Units. References hereunder to an Eligible Employee as a Management Incentive Member will be deemed to refer to the Eligible Employee Affiliate affiliated with such Eligible Employee that is a Management Incentive Member such that anything occurring with respect to the Eligible Employee that is affiliated with such Eligible Employee Affiliate will be deemed to have occurred with respect to such Eligible Employee Affiliate.

4. Management Incentive Units under the Plan.

4.1 Number of Units. The maximum number of authorized Management Incentive Units to be issued under the Plan will be 1,000,000 or such greater number as is approved by the Board of Managers. Each issued and outstanding Management Incentive Unit will be entitled to share in the allocations and distributions to be made to Management Incentive Members as provided in the Company Agreement. If any issued Management Incentive Unit awarded under the Plan is forfeited or repurchased for any reason, such Management Incentive Unit will be added back to the Plan and will be available for awards under the terms and conditions of the Plan and the Company Agreement. If any issued Management Incentive Unit awarded under the Plan is repurchased by the Company, such Management Incentive Unit will thereafter be available for awards under the Plan and the Company Agreement (subject to the approval of other requirements thereof) and, until reissued, shall be considered authorized but not outstanding).

4.2 Voting. Management Incentive Units will not be entitled to vote pursuant to the express terms of the Company Agreement.

4.3 Lack of Transferability. Management Incentive Units will not be transferable without the written consent of the Board of Managers and then only for estate planning purposes. The Managing Member may recommend, subject to the approval of the Board of Managers, acceleration in whole or in part of vesting upon the death or Disability of the holder of Management Incentive Units. In the event the Board of Managers approves the vesting of the Management Incentive Units upon the death or Disability of the holder thereof, the terms of such accelerated vesting will be reflected in such holder's Employment Agreement or Award Letter. Notwithstanding the foregoing transfer restrictions, Management Incentive Units that become vested upon the death of any holder shall be transferable pursuant to such holder's will or the laws of descent and distribution in the absence of a will. Any vested Management Incentive Units that are transferred upon death of a holder as provided in the preceding sentence

shall be subject to repurchase by the Company on terms substantially similar to those set forth in Section 9.4 of the Company Agreement.

4.4 *Access to Books and Records*. The Management Incentive Members (other than a Management Incentive Member that is also a Manager) will not have any right under the Act or the Company Agreement to have access to (i) the number of Management Incentive Units issued to any other Management Incentive Member or (ii) the books and records of the Company pursuant to the terms and conditions of the Act and the Company Agreement.

5. Awarding of Management Incentive Units. Unissued Management Incentive Units may be awarded under the Plan at any time on or after the date hereof pursuant to an Award Letter in such form as approved by the Board of Managers. The date of the award of a Management Incentive Unit under the Plan will be the date specified in the Award Letter; provided, however, that such date will not be prior to the date on which the Board of Managers approves the award.

6. Vesting and Forfeiture of Management Incentive Units. Subject to the provisions of paragraphs 7 through 10, and unless otherwise provided in an Employment Agreement or Award Letter governing the vesting and forfeiture of Management Incentive Units granted to any Management Incentive Member:

6.1 *Vesting.* All Management Incentive Units granted to and held by any Management Incentive Member shall vest automatically immediately prior to, but conditioned upon, the consummation of a Final Exit Event or a liquidation and winding up of the Company pursuant to Article 8 of the Company Agreement.

6.2 *Full Vesting of Installments.* Once a Management Incentive Unit becomes vested pursuant to the terms herein or of a relevant Employment Agreement or Award Letter, it will remain vested and, except as provided in Section 6.4 of this Plan, not subject to forfeiture unless such recipient's Business Relationship (as defined below) is terminated for Cause (as defined below) or as otherwise specified by the Board of Managers and set forth in the Employment Agreement or Award Letter or the Company Agreement.

6.3 *Acceleration or Waiver of Vesting.* The Board of Managers will have the right to accelerate the date that any Management Incentive Unit becomes vested or waive vesting requirements, in whole or in part, contained herein or in any Employment Agreement or Award Letter for any reason or for no reason, in the sole discretion of the Board of Managers.

6.4 *Defaulting Member.* If any Management Incentive Member or any Affiliate of such Management Incentive Member becomes a Defaulting Member, the Management Incentive Units held by such Management Incentive Member and any or all of such Management Incentive Member's Permitted Transferees, whether vested or unvested, shall be forfeited to the Company for no consideration.

7. Termination of Business Relationship. Each Award Letter may provide that the Management Incentive Units awarded thereby will be forfeited before their stated vesting dates, upon terms specified by the Board of Managers, if the owner ceases to be an Eligible Employee of the Company (any such relationship hereinafter referred to as a "*Business Relationship*"), or if

the owner otherwise fails to satisfy vesting requirements with respect to Management Incentive Units awarded under this Plan. Nothing in the Plan, any Employment Agreement or in any Award Letter will be deemed to give any owner the right to continue his Business Relationship for any period of time.

8. Consequences of Termination.

8.1 Termination for Cause. Unless otherwise specified in a relevant Employment Agreement or Award Letter, if a Management Incentive Member's Business Relationship is terminated by the Company or its Affiliates for Cause, then such Management Incentive Member and any or all of such Management Incentive Member's Permitted Transferees will forfeit to the Company all of the Management Incentive Units, whether vested or unvested, held by such Management Incentive Member and such Permitted Transferees for no consideration. Unless otherwise specified in the relevant Employment Agreement or Award Letter, "*Cause*" shall mean the Management Incentive Member's (i) conviction or plea of *nolo contendere* in a court of law, or imposition of unadjudicated probation for any felony (or any other crime involving fraud, embezzlement or misappropriation) or the Management Incentive Member's entering into a consent decree relating to any violations of U.S. or foreign securities laws, (ii) willful misconduct or gross negligence in connection with the business or affairs of the Company or its Affiliates, (iii) engagement in conduct that violates the Company's then existing internal policies or procedures that is detrimental to the business, reputation, character or standing of the Company or any of its Affiliates, (iv) substance abuse, including abuse of alcohol, drugs or other substances or use of illegal narcotics or substances, for which the Management Incentive Member fails to undertake treatment immediately after requested by the Board of Managers or to complete such treatment and which abuse continues or resumes after such treatment period, or possession of illegal narcotics or substances on the premises of the Company or its Affiliates or while performing the Management Incentive Member's duties and responsibilities, (v) misappropriation of funds or other acts of material dishonesty involving the Company or its Affiliates, (vi) continuing failure or refusal to perform in all material respects the Management Incentive Member's duties and responsibilities or to carry out in all material respects the lawful directives of the Board of Managers that remains uncorrected 30 days after the Management Incentive Member receives written notice of such failure or refusal or (vii) material breach of the terms of the Company Agreement or any other agreement between the Management Incentive Member and the Company or its Affiliates.

8.2 Other Cessation of Business Relationship. Unless otherwise specified in a relevant Employment Agreement or Award Letter, if a Management Incentive Member's Business Relationship is terminated as a result of the termination by the Company without Cause, or death, Disability or resignation of such person, then such Management Incentive Member and any or all of such Management Incentive Member's Permitted Transferees will forfeit to the Company all of the unvested Management Incentive Units held by such Management Incentive Member and such Permitted Transferees for no consideration, and the Company will have the option to purchase all of the vested Management Incentive Units held by such Management Incentive Member and such Permitted Transferees at the time and for the amount determined in the manner provided in Section 9.4 of the Company Agreement. The Company's options hereunder may be exercised at any time within ninety (90) days from the termination such Person's Business Relationship.

9. Terms and Conditions of Awards of Management Incentive Units. All awards of Management Incentive Units under this Plan will be evidenced by Employment Agreements or Award Letters (which need not be identical) signed by the Company.

10. Adjustments. Management Incentive Units awarded hereunder will be adjusted as hereinafter provided, unless otherwise specifically provided in the Employment Agreement or Award Letter relating to such Management Incentive Unit:

10.1 Management Incentive Units Distributions and Splits. If the Management Incentive Units will be subdivided or combined into a greater or smaller number of Management Incentive Units or if the Company will issue any Management Incentive Units as a distribution on its outstanding Management Incentive Units, the number of Management Incentive Units subject to an award of Management Incentive Units hereunder will be increased or decreased proportionately.

10.2 Issuances of Interests. Except as expressly provided herein and in the Company Agreement, no issuance by the Company of equity or debt instruments of any class will affect, and no adjustment by reason thereof will be made with respect to, the number of Management Incentive Units.

10.3 Fractional Units. No fractional Management Incentive Units will be issued under the Plan (but fractional Management Incentive Units may become vested pursuant to a percentage vesting schedule).

10.4 Increase in Authorized Management Incentive Units. Upon the happening of any of the events described in subparagraph 10.1 above, the aggregate number of Management Incentive Units set forth in paragraph 4 hereof that may be awarded under the Plan will also be appropriately adjusted to reflect the events described in such subparagraph. The Board of Managers will determine the specific adjustment to be made under this paragraph 10, if any, and its determination will be conclusive.

11. Amendment of Plan. Subject to the provisions of the Company Agreement and the applicable Employment Agreement or Award Letter, the Board may terminate or amend the Plan in any respect at any time, except as otherwise provided in this Plan, the Company Agreement, any Employment Agreement or any Award Letter; provided, however, that in no event may any action of the Board alter or impair the rights of any holder, without consent of the holder, with respect to any Management Incentive Unit previously awarded to such holder.

12. Application of Funds. The proceeds received by the Company, if any, from the issuance of Management Incentive Units to a holder under the Plan may be used for any Company purpose.

13. Withholding of Income Taxes. Upon the award of any Management Incentive Units, the vesting or transfer of Management Incentive Units, or the making of a distribution or other payment with respect to such Management Incentive Units, the Company may withhold taxes in respect of amounts that the Company, in its discretion, determines constitute compensation includible in gross income. The Board of Managers, in its sole discretion, may condition (i) the award of a Management Incentive Unit or (ii) the transferability of a

Management Incentive Unit on the holder's making satisfactory arrangement for such withholding. Such arrangement may include payment by the holder in cash or by check of the amount of the withholding taxes or, at the sole discretion of the Board of Managers, by the holder's delivery of previously held Management Incentive Units, or fractions thereof, having an aggregate fair market value equal to the amount of such withholding taxes.

14. Section 83(b) Election. The Board of Managers may condition the award of any Management Incentive Unit upon (i) the filing, within thirty (30) days after such award, by the Management Incentive Member with the Internal Revenue Service of an election, in appropriate form, authorized by section 83(b) of the Code (an "*83(b) Election*") with respect to the Management Incentive Units and delivery to the Company of a copy of such 83(b) Election promptly after its filing or (ii) the execution and delivery to the Company by the Management Incentive Member of a written covenant to file an 83(b) Election with respect to the Management Incentive Units and delivery of a copy thereof to the Company within 30 days after the award of the Management Incentive Units.

15. Governmental Regulation. The Company's obligation to sell and deliver the Management Incentive Units under this Plan is subject to the approval of any governmental authority required in connection with the authorization, issuance or sale of such Management Incentive Units. Government regulations may impose reporting or other obligations on the Company with respect to the Plan. For example, the Company may be required to file tax information returns reporting the income received by holders in connection with the Plan.

16. Governing Law. The validity and construction of the Plan and the relevant provisions of an Employment Agreement or Award Letter evidencing awards of Management Incentive Units will be governed by the laws of the State of Delaware.

17. Section 409A Savings Clause. If any compensation or benefits provided by the Plan may result in the application of Section 409A of the Code, the Company shall, in consultation with the Board of Managers, modify the Plan in order to, where applicable, (a) exclude such compensation from the definition of "deferred compensation" within the meaning of Section 409A of the Code or (b) comply with the provisions of Section 409A of the Code, other applicable provision(s) of the Code and/or any rules, regulations or other regulatory guidance issued under such statutory provision and to make such modifications; in each case, without any diminution in the value of the benefits to the Management Incentive Members; provided, that any such modification of the Plan will not be in violation of Section 409A of the Code or have a significant adverse effect on the Company or the Common Units.

18. BOARD DETERMINATIONS; DISPUTE RESOLUTION; CONSENT TO EXCLUSIVE JURISDICTION. ALL DISPUTES BETWEEN OR AMONG ANY PERSONS ARISING OUT OF OR IN ANY WAY CONNECTED WITH THIS PLAN, ANY AWARD LETTER OR ANY AWARD OF UNITS UNDER THIS PLAN (INCLUDING ANY INTERPRETATION OF THE COMPANY AGREEMENT AS IT PERTAINS TO THE UNITS AWARDED UNDER THIS PLAN) WILL BE SOLELY AND FINALLY SETTLED BY THE BOARD OF MANAGERS EXCLUDING ANY MANAGER THAT IS PARTY TO THE DISPUTE, THE DETERMINATION OF WHICH WILL BE FINAL AND BINDING. ANY MATTERS NOT COVERED BY THE PRECEDING SENTENCE, BUT WHICH ARISE

UNDER THE COMPANY AGREEMENT, WILL BE SOLELY AND FINALLY SETTLED IN ACCORDANCE WITH THE COMPANY AGREEMENT, AND EACH PERSON ACCEPTING AN AWARD UNDER THE PLAN AND THE COMPANY CONSENT TO THE EXCLUSIVE PERSONAL JURISDICTION OF THE CHANCERY COURT OF THE STATE OF DELAWARE, AS THE EXCLUSIVE JURISDICTION WITH RESPECT TO MATTERS ARISING OUT OF OR RELATED TO THE ENFORCEMENT OF THE BOARD OF MANAGERS' DETERMINATIONS AND RESOLUTION OF MATTERS, IF ANY, RELATED TO THE PLAN OR THE COMPANY AGREEMENT NOT REQUIRED TO BE RESOLVED BY THE BOARD OF MANAGERS. EACH SUCH PERSON HEREBY IRREVOCABLY CONSENTS TO THE SERVICE OF PROCESS OF THE AFOREMENTIONED COURT IN ANY SUCH SUIT, ACTION OR PROCEEDING BY THE MAILING OF COPIES THEREOF BY REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID, TO THE LAST KNOWN ADDRESS OF SUCH PERSON, SUCH SERVICE TO BECOME EFFECTIVE TEN (10) DAYS AFTER SUCH MAILING.

19. Rule 701 Plan. The arrangements contemplated by this Plan constitute a "written compensation contract" within the meaning of Rule 701(c) of the Securities Act.

ANNEX A

FORM OF AWARD LETTER

Exaro Energy III LLC, a Delaware limited liability company (the "Company"), hereby grants to _____ (the "Participant"), an Eligible Employee, as defined in the Management Incentive Plan of the Company, as amended from time to time (the "Plan"), an award of _____ Management Incentive Units ("MIUs"), subject to the following terms and conditions:

1. **Relationship to Plan**. This Award Letter is issued in accordance with and subject to all of the terms, conditions and provisions of the Plan, a copy of which is attached hereto as Exhibit A, and administrative interpretations thereunder, if any, which have been or may be adopted by the Board of Managers. Except as defined herein, capitalized terms shall have the same meanings ascribed to them under the Plan.

2. **Vesting**. The MIUs awarded pursuant to this Award Letter shall vest in five installments as provided below, provided that the Participant remains employed by the Company, one of its Subsidiaries or the Management Company on the relevant date.

Date	Number of Vested MIUs
Prior to the [__] anniversary of the Grant Date	0
On or after the [__]anniversary of the Grant Date	_____
On or after the [__] anniversary of the Grant Date	_____
On or after the [__] anniversary of the Grant Date	_____

3. **Condition.** This award is conditioned upon the Participant filing a valid election under Section 83(b) of the Internal Revenue Code of 1986, as amended, with the Internal Revenue Service with respect to the receipt of the MIUs within 30 days of the Grant Date.

4. **Deemed Exercise Price.** The Deemed Exercise Price per MIU of each MIU issued pursuant to this Award Agreement is $_____.

In witness whereof, the undersigned has executed and delivered this Award Letter this __ day of _____, _____ (the "Grant Date").

EXARO ENERGY III LLC

By
Name:
Title:

EXHIBIT C
ALLOCATIONS AND TAX PROCEDURES

C.1 **Definitions**. Capitalized words and phrases used in this Exhibit C have the meaning ascribed to them in the Agreement except as otherwise provided below:

C.1.1 "*Adjusted Capital Account Deficit*" means, with respect to any Member, the deficit balance, if any, in such Member's Capital Account as of the end of the relevant Fiscal Year, after giving effect to the following adjustments:

C.1.1(a) Credit to such Capital Account any amounts which such Member is obligated to restore pursuant to any provision of this Agreement or is deemed to be obligated to restore pursuant to the penultimate sentences of Treas. Reg. §§1.704-2(g)(1) and 1.704-2(i)(5); and

C.1.1(b) Debit to such Capital Account the items described in Treas. Reg. §§1.704-1(b)(2)(ii)(d)(4), 1.704-1(b)(2)(ii)(d)(5), and 1.704- 1(b)(2)(ii)(d)(6).

The foregoing definition of Adjusted Capital Account Deficit is intended to comply with the provisions of Treas. Reg. §1.704-1(b)(2)(ii)(d) and shall be interpreted consistently therewith.

C.1.2 "*Capital Account*" means, with respect to any Member, the Capital Account maintained for such Member in accordance with the following provisions:

C.1.2(a) To each Member's Capital Account there shall be credited (A) the amount of cash and the Gross Asset Value of any property contributed by such Member to the capital of the Company, (B) such Member's distributive share of Profits and any items in the nature of income or gain which are specially allocated pursuant to Section C.4 hereof, and (C) the amount of any Company liabilities assumed by such Member or which are secured by any property distributed to such Member. The principal amount of a promissory note which is not readily tradable on an established securities market and which is contributed to the Company by the maker of the note (or a Member related to the maker of the note within the meaning of Treas. Reg. §1.704-1(b)(2)(ii)(c)) shall not be included in the Capital Account of any Member until the Company makes a taxable disposition of the note or until (and to the extent) principal payments are made on the note, all in accordance with Treas. Reg. §1.704-1(b)(2)(iv)(d)(2).

C.1.2(b) To each Member's Capital Account there shall be debited (A) the amount of cash and the Gross Asset Value of any property distributed to such Member pursuant to any provision of this Agreement, (B) such Member's distributive share of Losses and any items in the nature of expenses or losses which are specially allocated pursuant to Section C.4 hereof, and (C) the amount of any liabilities of such Member assumed by the Company or which are secured by any property contributed by such Member to the Company.

C.1.2(c) In the event all or a portion of a Member's Interest is Transferred in accordance with the terms of this Agreement, the transferee shall succeed to the Capital Account of the transferor to the extent it relates to the Transferred Interest;

C.1.2(d) In determining the amount of any liability for purposes of Section C.1.2(a) and Section C.1.2(b) above, there shall be taken into account section 752(c) of the Code and any other applicable provisions of the Code and Treasury Regulations; and

C.1.2(e) The allocation of depletable basis in, depletion allowances with respect to, and taxable gain or loss from the sale, exchange or other disposition of, the Company's depletable properties provided for in section 613A(c)(7)(D) of the Code shall be disregarded. Instead, depletion allowances with respect to, and taxable gain or loss from the sale, exchange or other disposition of, the Company's depletable properties shall be determined by taking into account Simulated Depletion and Simulated Gain or Loss, as determined and defined in the following sentence. For purposes of determining Simulated Depletion and Simulated Gain or Loss, (i) the Company's basis in its depletable properties ("*Simulated Basis*") shall equal the Gross Asset Value of such properties, (ii) the Company shall determine the depletion allowance ("*Simulated Depletion*") with respect to such depletable properties by using either the cost depletion method or the percentage depletion method (as determined by the Board of Managers on a property by property basis), (iii) the Company shall reduce the Simulated Basis of such depletable properties by the Simulated Depletion attributable to such depletable properties, and (iv) the Company shall compute gain or loss on a sale, exchange, or other disposition of such depletable properties by subtracting Simulated Basis from the amount realized by the Company upon such disposition ("*Simulated Gain or Loss*"). This Section C.1.2(e) is intended to comply with Treas. Reg. §1.704-1(b)(2)(iv)(k), and shall be interpreted and applied in a manner consistent therewith.

The foregoing provisions and the other provisions of this Agreement relating to the maintenance of Capital Accounts are intended to comply with Treas. Reg. §1.704-1(b), and shall be interpreted and applied in a manner consistent therewith. In the event the Board of Managers shall determine that it is prudent to modify the manner in which the Capital Accounts, or any debits or credits thereto (including debits or credits relating to liabilities which are secured by contributed or distributed property or which are assumed by the Company or the Members), are computed in order to comply with Treas. Reg. §1.704-1(b), the Board of Managers may make such modification, provided that it does not have an adverse effect on the amount or timing of a distribution to any Member pursuant to this Agreement. The Board of Managers also shall (i) make any adjustments that are necessary or appropriate to maintain equality between the Capital Accounts of the Members and the amount of Company capital reflected on the Company's balance sheet, as computed for book purposes, in accordance with Treas. Reg. §1.704-1(b)(2)(iv)(q), and (ii) make any appropriate modifications in the event unanticipated events might otherwise cause this Agreement not to comply with Treas. Reg. §1.704-

1(b), provided that such adjustment may not have an adverse effect on any Member who does not consent to such adjustment.

C.1.3 "*Code*" means the Internal Revenue Code of 1986, as amended and in effect from time to time, as interpreted by the applicable regulations thereunder.

C.1.4 "*Company Minimum Gain*" has the meaning set forth in Treas. Reg. §§1.704-2(b)(2) and 1.704-2(d) for partnership minimum gain.

C.1.5 "*Depreciation*" means, for each Fiscal Year, an amount equal to the depreciation, amortization, or other cost recovery deduction allowable for federal income tax purposes with respect to an asset for such Fiscal Year, except that if the Gross Asset Value of an asset differs from its adjusted basis for federal income tax purposes at the beginning of such Fiscal Year, Depreciation shall be an amount which bears the same ratio to such beginning Gross Asset Value as the federal income tax depreciation, amortization, or other cost recovery deduction for such Fiscal Year bears to such beginning adjusted tax basis; provided, however, that if the federal income tax depreciation, amortization, or other cost recovery deduction for such Fiscal Year is zero, Depreciation shall be determined with reference to such beginning Gross Asset Value using any reasonable method selected by the Board of Managers.

C.1.6 "*Gross Asset Value*" means, with respect to any asset, the asset's adjusted basis for federal income tax purposes, except as follows:

C.1.6(a) The initial Gross Asset Value of any asset contributed by a Member to the Company shall be the gross fair market value of such asset, as determined by the Board of Managers in their sole discretion.

C.1.6(b) The Gross Asset Values of all Company assets shall be adjusted to equal their respective gross fair market values (taking section 7701(g) of the Code into account), as determined by the Board of Managers in their sole discretion, as of the following times: (A) the acquisition of an additional interest in the Company by any new or existing Member in exchange for more than a de minimis capital contribution; (B) the distribution by the Company to a Member of more than a de minimis amount of property as consideration for an interest in the Company; (C) the liquidation of the Company within the meaning of Treas. Reg. §1.704-1(b)(2)(ii)(g) and (D) the grant of more than a de minimis interest in the Company in consideration for the provision of services to or for the benefit of the Company by a new or existing Member; provided, however, that adjustments pursuant to clauses (A), (B) and (D) above shall be made only if the Board of Managers reasonably determine that such adjustments are necessary or appropriate to reflect the relative economic interests of the Members in the Company.

C.1.6(c) The Gross Asset Value of any Company asset distributed to any Member, shall be adjusted to equal the gross fair market value taking into account section 7701(g) of the Code into account) of such asset on the date of distribution, as determined by the Board of Managers in their sole discretion.

C.1.6(d) The Gross Asset Values of Company assets shall be increased (or decreased) to reflect any adjustments to the adjusted basis of such assets pursuant to section 734(b) or section 743(b) of the Code, but only to the extent that such adjustments are taken into account in determining Capital Accounts pursuant to Treas. Reg. §1.704-1(b)(2)(iv)(m), subparagraph (f) of the definition of "*Profits*" and "*Losses*" and Section C.4.8 hereof; provided, however, that Gross Asset Values shall not be adjusted pursuant to this subparagraph (d) to the extent the Board of Managers determines that an adjustment pursuant to subparagraph (b) hereof is necessary or appropriate in connection with a transaction that would otherwise result in an adjustment pursuant to this subparagraph (d).

C.1.6(e) If the Gross Asset Value of an asset has been determined or adjusted pursuant to subparagraphs (a), (b) or (d) hereof, such Gross Asset Value shall thereafter be adjusted by the Depreciation or Simulated Depletion taken into account with respect to such asset for purposes of computing Profits and Losses.

C.1.6(f) The Gross Asset Value of the rights of the Company with respect to the Earning and Development Agreement with Encana Oil & Gas (USA) Inc. shall be adjusted as of the date hereof pursuant to this provision to equal $500,000 immediately prior to the admission pursuant to the terms hereof of the Members of the Company other than Clark.

C.1.7 "*Member Nonrecourse Debt*" has the meaning set forth in Treas. Reg. §1.704-2(b)(4) for partner nonrecourse debt.

C.1.8 "*Member Nonrecourse Debt Minimum Gain*" means an amount, with respect to each Member Nonrecourse Debt, equal to the Company Minimum Gain that would result if such Member Nonrecourse Debt were treated as a Nonrecourse Liability, determined in accordance with Treas. Reg. §1.704-2(i)(3).

C.1.9 "*Member Nonrecourse Deductions*" has the meaning set forth in Treas. Reg. §§1.704-2(i)(1) and 1.704-2(i)(2) for partner nonrecourse deductions.

C.1.10 "*Nonrecourse Deductions*" has the meaning set forth in Treas. Reg. §§1.704-2(b)(1) and 1.704-2(c). The amount of Nonrecourse Deductions for a Fiscal Year shall generally equal the net increase, if any, in the amount of Company Minimum Gain for that Fiscal Year, reduced (but not below zero) by the aggregate distributions during the-year-of-proceeds-of Nonrecourse Liabilities that are allocable to an increase in Company Minimum Gain, with such other modifications as provided in Treas. Reg. §1.704-2(c).

C.1.11 "*Nonrecourse Liability*" has the meaning set forth in Treas. Reg. §1.704-2(b)(3).

C.1.12 "*Partially Adjusted Capital Account*" shall mean with respect to any Member and any Fiscal Year, the Capital Account of such Member at the beginning of such Fiscal Year, adjusted as set forth in the definition of Capital Account for all contributions and distributions during such year and all special allocations pursuant to

Section C.4 hereof with respect to such Fiscal Year, but before giving effect to any allocations of Profits and Losses for such Fiscal Year pursuant to Section C.2 and Section C.3.

C.1.13 "*Profits*" and "*Losses*" means, for each Fiscal Year, an amount equal to the aggregate (if positive or negative respectively) of the Company's items of income or loss for federal income tax purposes for such Fiscal Year, determined in accordance with section 703(a) of the Code (for this purpose, all items of income, gain, loss, or deduction required to be stated separately pursuant to section 703(a)(1) of the Code shall be included in taxable income or loss), with the following adjustments (without duplication) as to such items:

C.1.13(a) Any income of the Company that is exempt from federal income tax and not otherwise taken into account in computing Profits or Losses pursuant to this definition of "Profits" and "Losses" shall be added to such taxable income or loss.

C.1.13(b) Any expenditures of the Company described in section 705(a)(2)(B) of the Code or treated as section 705(a)(2)(B) of the Code expenditures pursuant to Treas. Reg. §1.704-1(b)(2)(iv)(i), and not otherwise taken into account in computing Profits or Losses pursuant to this definition of "Profits" and "Losses" shall be subtracted from such taxable income or loss.

C.1.13(c) In the event the Gross Asset Value of any property is adjusted pursuant to subparagraphs (b) or (c) of the definition of "Gross Asset Value," hereof, the amount of such adjustment shall be treated as an item of gain (if the adjustment increases the Gross Asset Value of the asset) or an item of loss (if the adjustment decreases the Gross Asset Value of the asset) from the disposition of such asset and shall be taken into account for purposes of computing Profits or Losses.

C.1.13(d) Gain or loss resulting from any disposition of property with respect to which gain or loss is recognized for federal income tax purposes shall be computed by reference to the Gross Asset Value of the property disposed of, notwithstanding that the adjusted tax basis of such property differs from its Gross Asset Value.

C.1.13(e) In lieu of the depreciation, amortization, and other cost recovery deductions taken into account in computing such taxable income or loss, there shall be taken into account Depreciation for such Fiscal Year, computed in accordance with the definition of "Depreciation."

C.1.13(f) To the extent an adjustment to the adjusted tax basis of any Company asset pursuant to section 734(b) or section 743(b) of the Code is required pursuant to Treas. Reg. §1.704-1(b)(2)(iv)(m)(4) to be taken into account in determining Capital Accounts as a result of a distribution other than in complete liquidation of a Member's interest in the Company, the amount of such

adjustment shall be treated as an item of gain (if the adjustment increases the basis of the asset) or loss (if the adjustment decreases such basis) from the disposition of such asset and shall be taken into account for purposes of computing Profits or Losses.

C.1.13(g) Any items which are specially allocated pursuant to Section C.4 hereof shall not be taken into account in computing Profits or Losses. The amounts of the items of Company income, gain, loss, or deduction available to be specially allocated pursuant to Section C.4 hereof shall be determined by applying rules analogous to those set forth in subparagraphs (a) through (f) above.

C.1.14 "*Target Capital Account*" means, with respect to any Member and for any Fiscal Year, the Tentative Target Capital Account Balance (as hereinafter defined) reduced as provided herein. The Tentative Target Capital Account Balance is:

C.1.14(a) the amount, if any, that a Member would receive pursuant to the provisions hereof if all Company assets were sold for cash equal to their Gross Asset Value (or if required or permitted by any agreement or instrument by which the Company is bound are instead applied to pay or discharge one or more obligations of the Company if such application would increase the aggregate amount that would so be distributed to the Members), all Company liabilities, were satisfied to the extent required by their terms and the remaining assets were distributed in full to the Members as provided in Section 8.2 reduced by

C.1.14(b) any contribution that such Member would be required to make pursuant to this Agreement in connection with the hypothetical distribution that is described in Section C.1.14(a).

The Target Capital Account of a Member is the Tentative Capital Account Balance of that Member reduced by the amount of income that would be allocated to such Member as a result of the hypothetical liquidation that is described in Section C.1.14(a) (which will principally be recapture of Member Nonrecourse Deductions and Nonrecourse Deductions).

C.1.15 "*Treasury Regulation*" or "*Treas. Reg.*" means any temporary or final income tax regulation issued by the United States Treasury Department.

C.2 **Profits**. After giving effect to the special allocations set forth in Section C.4 hereof, Profits for any Fiscal Year shall be allocated among the Members so as to reduce, proportionately, the differences between their respective Target Capital Accounts and Partially Adjusted Capital Accounts for such Fiscal Year. No portion of the Profits for any Fiscal Year shall be allocated to a Member whose Partially Adjusted Capital Account is greater than or equal to its Target Capital Account for such Fiscal Year.

C.3 **Losses**. After giving effect to the special allocations set forth in Section C.4 hereof, Losses for any Fiscal Year shall be allocated as set forth in Section C.3.1 below, subject to the limitation in Section C.3.2 below:

C.3.1 Losses for any Fiscal Year shall be allocated among the Members in proportion to the differences between their respective Partially Adjusted Capital Accounts and Target Capital Accounts for such Fiscal Year.

C.3.2 The Losses allocated pursuant to Section C.3.1 hereof shall not exceed the maximum amount of Losses that can be so allocated without causing any Member to have an Adjusted Capital Account Deficit at the end of any Fiscal Year. In the event some but not all of the Members would have Adjusted Capital Account Deficits as a consequence of an allocation of Losses pursuant to Section C.3.1, the limitation set forth in this Section C.3.2 shall be applied on a Member by Member basis so as to allocate. the maximum permissible Losses to each Member under Treas. Reg. §1.704-1(b)(2)(ii)(d).

C.4 **Special Allocations**. The following special allocations shall be made in the following order and priority:

C.4.1 *Minimum Gain Chargeback.* Notwithstanding any other provision of this Agreement, if there is a net decrease in Company Minimum Gain during any Fiscal Year, each Member shall be specially allocated items of Company income and gain for such Fiscal Year (and, if necessary, subsequent Fiscal Years) as required by Treas. Reg. §1.704-2(f). This Section C.4.1 is intended to comply with the minimum gain chargeback requirement in Treas. Reg. §1.704-2(f) and shall be interpreted consistently therewith.

C.4.2 *Member Nonrecourse Debt Minimum Gain Chargeback.* Notwithstanding any other provision of this Agreement, if there is a net decrease in Member Nonrecourse Debt Minimum Gain attributable to a Member Nonrecourse Debt during any Fiscal Year, each Member shall be specially allocated items of Company income and gain for such Fiscal Year (and, if necessary, subsequent Fiscal Years) in an amount equal to such Member's share of the net decrease in Member Nonrecourse Debt Minimum Gain attributable to such Member Nonrecourse Debt, determined in accordance with Treas. Reg. §§1.704-2(i)(4). This Section C.4.2 is intended to comply with the partner nonrecourse debt minimum gain chargeback requirement in Treas. Reg. §1.704-2(i)(4) and shall be interpreted consistently therewith.

C.4.3 *Qualified Income Offset.* In the event any Member unexpectedly receives any adjustments, allocations, or distributions described in Treas. Reg. §§1.704-1(b)(2)(ii)(d)(4), 1.704-1(b)(2)(ii)(d)(5) or 1.704-1(b)(2)(ii)(d)(6), items of Company income and gain shall be specially allocated to each such Member in an amount and manner sufficient to eliminate, to the extent required by the Treasury Regulations, the Adjusted Capital Account Deficit of such Member as quickly as possible, provided that an allocation pursuant to this Section C.4.3 shall be made only if and to the extent that such Member would have an Adjusted Capital Deficit after all other allocations provided for in this Exhibit C have been tentatively made as if this Section C.4.3 were not in this Exhibit C. This Section C.4.3 is intended to comply with the qualified income offset requirement in Treas. Reg. §1.704-1(b)(2)(ii)(d) and shall be interpreted consistently therewith.

C.4.4 *Gross Income Allocation.* In the event any Member has a deficit Capital Account at the end of any Fiscal Year which is in excess of the sum of (i) the amount such Member is obligated to restore pursuant to any provision of this Agreement and (ii) the amount such Member is deemed to be obligated to restore pursuant to the penultimate sentences of Treas. Reg. §§1.704-2(g)(1) and 1.704-2(i)(5), each such Member shall be specially allocated items of Company income and gain in the amount of such excess as quickly as possible, provided that an allocation pursuant to this Section C.4.4 shall be made only if and to the extent that such Member would have a deficit Capital Account in excess of such sum after all other allocations provided for in this Agreement have been made as if Section C.4.3 hereof and this Section C.4.4 were not in this Exhibit C.

C.4.5 *Nonrecourse Deductions.* Nonrecourse Deductions for any Fiscal Year shall be specially allocated to the Members in the same ratio that Profit or Loss is allocated among the Members for such Fiscal Year.

C.4.6 *Member Nonrecourse Deductions.* Member Nonrecourse Deductions for any Fiscal Year shall be specially allocated to the Member who bears the economic risk of loss with respect to the Member Nonrecourse Debt to which such Member Nonrecourse Deductions are attributable in accordance with Treas. Reg. §1.704-2(i)(1); provided, however, that if more than one Member bears the economic risk of loss for such debt, the Member Nonrecourse Deductions attributable to such Member Nonrecourse Debt shall be allocated to and among the Members in the same proportion that they bear the economic risk of loss for such Member Nonrecourse Debt. This Section C.4.6 is intended to comply with the provisions of Treas. Reg. §1.704-2(i) and shall be interpreted consistently therewith.

C.4.7 *Simulated Depletion and Simulated Loss*. Simulated Depletion and Simulated Loss with respect to each property the production from which is subject to depletion shall be allocated to the Members in the same proportion that the Members (or their predecessors in interest) were allocated the adjusted tax basis of such property under Section C.7.5.

C.4.8 *Section 754 Adjustment.* To the extent that an adjustment to the adjusted tax basis of any Company asset pursuant to Code Section 734(b) or Code Section 743(b) is required, pursuant to Treas. Reg. §1.704-1(b)(2)(iv)(m)(2) or Treas. Reg. §1.704-1(b)(2)(iv)(m)(4), to be taken into account in determining Capital Accounts as the result of a distribution to a Member in complete liquidation of its interest in the Company, the amount of such adjustment to the Capital Accounts shall be treated as an item of gain (if the adjustment increases the basis of the asset) or loss (if the adjustment decreases such basis), and such gain or loss shall be specially allocated to the Members in the manner required by Treas. Reg. §1.704-1(b)(2)(iv)(m)(2) or Treas. Reg. §1.704-1(b)(2)(iv)(m)(4), as applicable.

C.5 **Intent of Allocations**. The parties intend that the allocation provisions of this Exhibit C shall produce final Capital Account balances of the Members that will be consistent

with liquidating distributions in accordance with Section 8.2 of this Agreement. To the extent that the allocations required in this Exhibit C would fail to produce such final Capital Account balances, (i) such allocation provisions shall be amended by the Board of Managers if and to the extent necessary to produce such result and (ii) items of Company income, gain, loss or deduction for prior open taxable years shall be reallocated by the Board of Managers among the Members to the extent it is not possible to achieve such result with allocations of Company income, gain, loss or deduction for the current taxable year and future taxable years.

C.6 **Other Allocation Rules**.

C.6.1 Profits, Losses or any other items allocable to any period shall be determined on a daily, monthly or other basis, as determined by the Board of Managers using any permissible method under section 706 of the Code and the Treasury Regulations thereunder.

C.6.2 The Members are aware of the income tax consequences of the allocations made in this Agreement and hereby agree to be bound by the provisions of this Agreement in reporting their shares of Company income and loss for income tax purposes.

C.6.3 Solely for purposes of determining a Member's proportionate share of the "excess nonrecourse liabilities" of the Company within the meaning of Treas. Reg. §1.752-3(a)(3), the Members' interests in Company profits shall be allocated in the same ratio that Profit or Loss is allocated among the Members for such Fiscal Year.

C.6.4 To the extent permitted by Treas. Reg. §1.704-2(h)(3), the Board of Managers shall endeavor to treat distributions as having been made from the proceeds of a Nonrecourse Liability or a Member Nonrecourse Debt only to the extent that such distributions would cause or increase an Adjusted Capital Account Deficit for any Member.

C.7 **Tax Allocations; Section 704(c) of the Code**.

C.7.1 In accordance with section 704(c) of the Code and the Treasury Regulations thereunder, income, gain, loss, and deduction with respect to any property contributed to the capital of the Company shall, solely for tax purposes, be allocated among the Members so as to take account of any variation between the adjusted basis of such property to the Company for federal income tax purposes and its initial Gross Asset Value (computed in accordance with subparagraph (a) of the definition of "*Gross Asset Value*"). The Company shall utilize with respect to each contributed property any method that is permitted by Treas. Reg. §1.704-3 that is selected by the Board of Managers after conferring with its tax advisors.

C.7.2 In the event the Gross Asset Value of any Company asset is adjusted pursuant to subparagraph (b) of the definition of "*Gross Asset Value,*" subsequent allocations of income, gain, loss, and deduction with respect to such asset shall take account of any variation between the adjusted basis of such asset for federal income tax purposes and its Gross Asset Value in any manner that it could take into account such

difference under section 704(c) of the Code and the Treasury Regulations thereunder by reason of Section C.7.1.

C.7.3 Any elections or other decisions relating to such allocations shall be made by the Board of Managers. Allocations pursuant to this Section C.7 are solely for purposes of federal, state, and local taxes and shall not affect, or in any way be taken into account in computing, any Member's Capital Account or share of Profits, Losses, other items, or distributions pursuant to any provision of this Agreement.

C.7.4 Except as otherwise provided in this Agreement, all items of Company income, gain, loss, deduction, and any other allocations not otherwise provided for shall be divided among the Members in the same proportions as the corresponding item of income, gain, loss and deduction was allocated for Capital Account purpose. For purposes of determining the nature (as ordinary or capital) of any Company gain allocated among the Members for Federal income tax purposes pursuant to this Agreement, the portion of such gain required to be recognized as ordinary income pursuant to section 1245, section 1250 and/or section 1254 of the Code shall be deemed to be allocated among the Members in accordance with Treas. Reg. §§1.1245-1(e)(2), 1.1250-1(f), and 1.1254-5.

C.7.5 *Depletion and Gain or Loss from Dispositions of Depletable Property.* Cost and percentage depletion deductions with respect to, and any gain or loss on the sale or other disposition of, any property the production from which is or would be (in the case of nonproducing properties) subject to depletion shall be determined in a manner that is consistent with section 613A(c)(7)(D) of the Code. For purposes of making such determination, the Company's adjusted tax basis in each depletable property shall be allocated under section 613A(c)(7)(D) of the Code among the Members in proportion to the distributions to which each Member would be entitled pursuant to Section 8.2 of the Agreement if the Company were liquidated immediately prior to the time such property is acquired. The portion of the amount realized on the sale or other disposition of each depletable property that does not exceed the Company's Simulated Basis in the depletable property shall be allocated among the Members in proportion to the ratio in which the tax basis of the property was allocated pursuant to the preceding sentence. The portion of the amount realized on the sale or other disposition of each depletable property that exceeds the Company's Simulated Basis therein shall be allocated among the Members in the same manner that Profits (i.e. Simulated Gain) are allocated pursuant to Section C.2 of this Exhibit C.

C.8 **Reliance on Advice of Accountants and Attorneys**. The Managers will have no liability to the Members or the Company if the Managers rely upon the written opinion of tax counsel or accountants retained by the Company with respect to all matters (including disputes) relating to computations and determinations required to be made under this Exhibit C or other related provisions of this Agreement.

EXHIBIT D
SHARING RATIOS
(assuming all Capital Commitments on the Second Amendment Date are fully contributed)

Member	Capital Contribution Ratio	First Flip Sharing Ratio (>10.0% IRR and ≤20.0% IRR and ≤2.0x)	Second Flip Sharing Ratio (>20.0% IRR and >2.0x and ≤20.0% IRR and ≤3.0x)	Third Flip Sharing Ratio (>20.0% IRR and >3.0x and ≤25.0% IRR and ≤4.0x)	Fourth Flip Sharing Ratio (>25.0% IRR and >4.0x)
Contaro	36.9211%	33.2290%	29.5368%	28.4292%	27.6908%
Sageview A	19.4724%	17.5252%	15.5780%	14.9938%	14.6043%
Sageview B	8.7517%	7.8765%	7.0013%	6.7388%	6.5637%
Sageview C	1.8597%	1.6738%	1.4878%	1.4320%	1.3948%
Sageview GenPar	1.3674%	1.2307%	1.0940%	1.0529%	1.0256%
Jefferies Capital Partners IV L.P.	16.6219%	14.9597%	13.2975%	12.7989%	12.4664%
Jefferies Employee Partners IV LLC	1.9145%	1.7230%	1.5316%	1.4741%	1.4358%
JCP Partners IV LLC	0.6079%	0.5471%	0.4863%	0.4681%	0.4559%
Union Bank	5.4698%	4.9228%	4.3758%	4.2117%	4.1023%
Wells Fargo	5.4698%	4.9228%	4.3758%	4.2117%	4.1023%
Beato Family Trust	0.6564%	0.5907%	0.5251%	0.5054%	0.4923%
Atwood	0.3419%	0.3077%	0.2735%	0.2632%	0.2564%
Clark	0.5128%	0.4615%	0.4102%	0.3949%	0.3846%
Russell	0.0328%	0.0295%	0.0263%	0.0253%	0.0246%
Total Common Unitholders	100.0000%	90.0000%	80.0000%	77.0000%	75.0000%
Management Incentive Members	0.0000%	10.0000%	20.0000%	23.0000%	25.0000%
Total	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

EXHIBIT E
INITIAL BUDGET

Estimated G&A Cost ($000s)	**Apr-12 - Sep-12**	**Oct-12 - Dec-12**	**2013**
C.Beato - President	$69	$63	$275
S. Clark - Senior VP President	$109	$57	$248
J. Atwood - Senior Vice President	$62	$57	$248
D. Battin - Senior Geologist	$60	$28	$120
B. Wheatley - GeoTech Analyst	$12	$22	$95
TBD - GeoTech	$38	$17	$75
S. Morales - Office Assistant	$7	$6	$27
T. Yu - Senior Accountant	$20	$18	$80
T. Pal - Controller	$35	$36	$156
Payroll Taxes	$50	$39	$169
Bonuses	$0	$275	$390
Medical, Dental, Vision Ins, Life, etc.	$61	$61	$243
Employer 401(k)/Retirement Plan	$17	$26	$113
Payroll Fees	$2	$2	$6
Reclassification / Reimbursements	($1)	($4)	($17)
Total Payroll and Benefits	$538	$703	$2,226
IT	$51	$50	$176
Reserve Report	$120	$60	$240
Bob Coskey	$60	$30	$120
Legal	$18	$9	$36
Accounting	$130	$15	$160
Insurance	$20	$14	$54
Travel and Entertainment	$45	$23	$90
Office Expenses	$12	$9	$36
Office Space	$33	$24	$96
Other Fees & Expenses	$12	$6	$24
Total G&A	**$1,039**	**$943**	**$3,258**

Estimated Capex ($000s)	**Apr-12 - Jun-12**	**Jul-12 - Sep-12**	**Oct-12 - Dec-12**
New Wells			
Rig: Ensign 129	$10,687	$12,376	$14,000
Rig: Ensign 134	$8,408	$7,280	$12,768
Rig: Ensign 157	$13,720	$9,792	$8,397
Total D&C Capex	$32,815	$29,448	$35,165
Other Capex[1]	$30		
Total Capex	**$32,845**	**$29,448**	**$35,165**

(1) Related to IT and furniture in the Denver office.

EXHIBIT F
FORM OF JOINDER AGREEMENT

The undersigned Member (the "Joining Member"), desiring to be admitted as a Member of Exaro Energy III LLC, a Delaware limited liability company (the "**Company**"), hereby agrees to be bound by the terms and conditions of, and to become a party to, that certain Second Amended and Restated Limited Liability Company Agreement dated effective as of February 1, 2013, as amended (the "**Company Agreement**"), as a "Member," as such term is defined in the Company Agreement. Capitalized terms that are used but not defined in this Joinder Agreement have the meanings set forth in the Company Agreement. The undersigned Joining Member further affirms and agrees that the undersigned's address for notice purposes pursuant to Section 11.1 of the Company Agreement shall be as follows:

The undersigned spouse of the Joining Member is executing this Joinder Agreement in order to acknowledge its terms and conditions, is aware of, understands and consents to the provisions of the Company Agreement, each other Transaction Document that has been or will be executed by the Joining Member or is otherwise binding on the Joining Member[, including that certain Award Letter, dated as of _____, 20__, between the Joining Member and the Company,] and its and such other agreements' binding effect upon any community property interest or marital settlement awards he or she may now or hereafter own or receive, and hereby agrees that the termination of his or her marital relationship with the Joining Member for any reason shall not have the effect of removing any Interests subject to the Company Agreement from the coverage thereof and that his or her awareness, understanding, consent and agreement is evidenced by his or her signature below.

IN WITNESS WHEREOF, this Joinder Agreement has been executed and delivered by the undersigned as of the __ day of ___, 20__.

Member

Spouse

EXHIBIT G
AREA OF MUTUAL INTEREST

Jonah Field

Sublette County, Wyoming

Township 28 North – Range 108 West, 6 P.M.

Sections 1-9, 18

Township 28 North – Range 109 West, 6 P.M.

Sections 1, 2, 11-14, 23, 24

Township 29 North – Range 107 West, 6 P.M.

Sections 5-9, 16-22, 27-33

Township 29 North – Range 108 West, 6 P.M.

Sections 1-36

EXHIBIT H
CLARK INTERESTS
(see attached)

Exhibit 21.1

CONTANGO OIL AND GAS COMPANY
LIST OF WHOLLY-OWNED SUBSIDIARIES
DECEMBER 31, 2018

Wholly-Owned Subsidiaries of Contango Oil & Gas Company as of 12/31/18

Crimson Exploration Inc.
Crimson Exploration Operating, Inc.
Contango Energy Company
Contango Rocky Mountain Inc.
Contango Operators, Inc.
Contango Mining Company
Conterra Company
Contaro Company
Contango Alta Investments, Inc.
Contango Venture Capital Corporation
LTW Pipeline Co.

Exhibit 21.2

CONTANGO OIL & GAS COMPANY
Corporate Structure
December 31, 2018

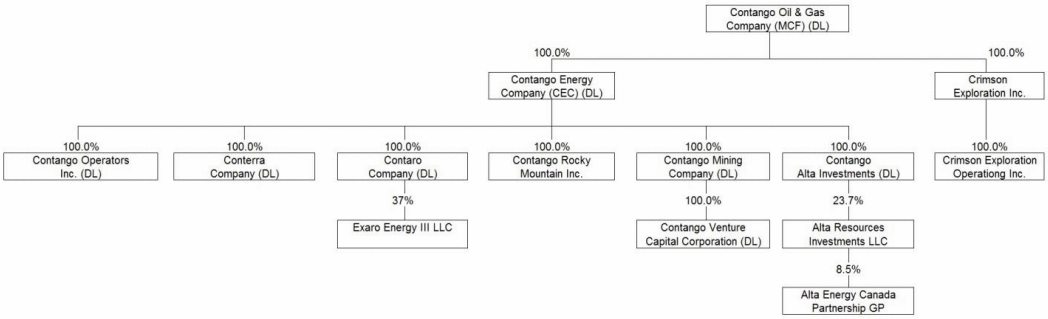


Exhibit 23.1

WILLIAM M. COBB & ASSOCIATES, INC.

Worldwide Petroleum Consultants

12770 Coit Road, Suite 907
Dallas, Texas 75251

(972) 385-0354
Fax: (972) 788-5165
E-Mail: office@wmcobb.com

March 18, 2019

Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, Texas 77002

Re: Contango Oil & Gas Company, Annual Report on Form 10-K

Gentlemen:

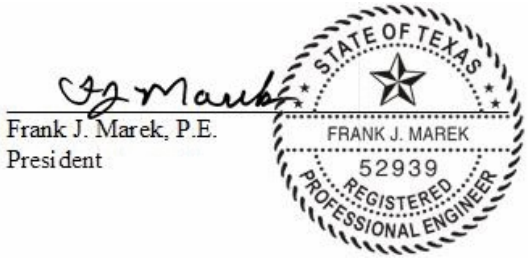
The firm of William M. Cobb & Associates, Inc. consents to the use of its name and to the use of its projections for Contango Oil & Gas Company's Proved Reserves and Future Net Revenue in Contango's Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333‑215784 and File No. 333-193613) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

William M. Cobb & Associates, Inc. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Sincerely,

WILLIAM M. COBB & ASSOCIATES, INC.
Texas Registered Engineering Firm F-84



Frank J. Marek, P.E.
President

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The firm of Netherland, Sewell & Associates, Inc. consents to the use of its name and to the use of its projections for Contango Oil & Gas Company's Proved Reserves and Future Net Revenue in Contango Oil & Gas Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333-215784 and File No. 333-193613) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

Netherland, Sewell & Associates, Inc. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Danny D. Simmons

By: _____

Danny D. Simmons, P.E.
President and Chief Executive Officer

Houston, Texas
March 18, 2019

Exhibit 23.3

W.D.Von Gonten&Co.
Petroleum Engineering 10496 Old Katy Road, Suite 200 Houston, Texas 77043 *t:* 713 224 6333 *f:* 713.224.6330 www.wdygco.com

W.D. VON GONTEN & CO.

March 18, 2019

Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, Texas 77002

Re: Contango Oil & Gas Company, Annual Report on Form 10-K

Gentlemen:

The firm of W.D. Von Gonten & Co. consents to the use of its name and to the use of its report regarding Contango Oil & Gas Company's Proved Reserves and Future Net Revenue associated with its 37% ownership interest in Exaro Energy III LLC, in Contango's Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333 215784 and File No. 333-193613) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

W.D. Von Gonten & Co. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Yours very truly,

W.D. VON GONTEN & CO.

Name: W.D. Von Gonten JR
Title: President

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 18, 2019, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Contango Oil & Gas Company on Form 10-K for the year ended December 31, 2018. We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333-215784 and File No. 333-193613) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

/s/ GRANT THORNTON LLP

Houston, Texas

March 18, 2019

Exhibit 31.1

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Wilkie S. Colyer, President and Chief Executive Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: March 18, 2019

By: /s/ WILKIE S. COLYER

Wilkie S. Colyer
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, E. Joseph Grady, Chief Financial Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: March 18, 2019

By: /s/ E. JOSEPH GRADY

E. Joseph Grady
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CONTANGO OIL & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Contango Oil & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2018 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Wilkie S. Colyer, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 18, 2019

By: /s/ WILKIE S. COLYER

Wilkie S. Colyer
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

CONTANGO OIL & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Contango Oil & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2018 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, E. Joseph Grady, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 18, 2019 By: /s/ E. JOSEPH GRADY

E. Joseph Grady
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 99.1

WILLIAM M. COBB & ASSOCIATES, INC.

Worldwide Petroleum Consultants

12770 Coit Road, Suite 907
Dallas, Texas

(972) 385-0354
Fax: (972) 788-5165
E-Mail: office@wmcobb.com

February 11, 2019

Ms. Christie Schultz
Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, TX 77002

Dear Ms. Schultz:

In accordance with your request, William M. Cobb & Associates, Inc. (Cobb & Associates) has estimated the proved reserves and future income as of January 1, 2019, attributable to the interest of Contango Oil & Gas Company and its subsidiaries (Contango) in certain oil and gas properties located in state and federal waters of the Gulf of Mexico, and onshore in Mississippi and Texas. This report was completed on February 11, 2019.

Table 1 summarizes our estimate of the proved oil and gas reserves and their pre-federal income tax value undiscounted and discounted at ten percent. Values shown are determined utilizing constant oil and gas prices and well operating expenses. The discounted present worth of future income values shown in Table 1 are not intended to necessarily represent an estimate of fair market value. These estimates were prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Certification Topic 932, Extraction Activities – Oil and Gas.

TABLE 1

CONTANGO - NET RESERVES AND VALUE
AS OF JANUARY 1, 2019
CONSTANT SEC OIL AND GAS PRICES

Reserve Category	Net Gas (MMCF)	Net NGL (MBBL)	Net Oil (MBBL)	Future Net Pre-Tax Income – M$	
				Undiscounted	Discounted at 10%
Proved					
Producing	41,654	1,820	2,110	220,506	147,119
Undeveloped	5,570	1,005	5,281	126,946	30,143
Total Proved	47,223	2,825	7,391	347,452	177,262

Total proved reserves as of January 1, 2019 are 108,519 MMCFE. This amount is calculated using a six MCF per barrel ratio applied to condensate and NGL volumes.

Oil and NGL volumes are expressed in thousands of stock tank barrels (MBBL). A stock tank barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of standard cubic feet (MMCF) as determined at 60° Fahrenheit and the legal pressure base for the specific location of the gas reserves.

Our report, which was prepared for Contango's use in filing with the SEC and will be filed with Contango's Form 10-K for fiscal year ended December 31, 2018 (the "Form 10-K"), covers 108,519 MMCFE, or 80.4 percent of the total company present value discounted at ten percent (PV10) presented in Contango's Form 10-K. We have used all assumptions, data, methods, and procedures considered necessary and appropriate to prepare this report.

DISCUSSION

Eugene Island 10

Eugene Island 10 is located in federal and state waters of the Gulf of Mexico, at a water depth of approximately 13 feet. Production is primarily from a single CibOp sand, the JRM-1 sand, at a depth of approximately 15,000 feet. The field was discovered in September, 2006 by the Contango Operators Dutch 1 well. Contango has since drilled four more wells, the Dutch 2, 3, 4 and 5, on Federal acreage. All five of the Dutch wells are currently active.

Contango's Louisiana State leases in this field are referred to as the Mary Rose prospect. Five Mary Rose wells have been drilled to date. Four Mary Rose wells, numbers 1 through 4, have produced from the main CibOp sand. The Mary Rose 4 well is depleted and has been abandoned. The Mary Rose 3 is also depleted, with abandonment scheduled for mid-2020.

The Mary Rose 5 well produces from a separate, and much smaller, CibOp reservoir that is now depleted. Abandonment of the Mary Rose 5 is scheduled for mid-2019.

All wells now produce to the Contango 'H' platform located in Eugene Island Block 11. The Dutch 1, 2, and 3 wells previously produced to the Chevron EI-24 platform but were switched to the Contango 'H' platform in 2013.

Proved reserves for the Eugene Island 10 main CibOp sand are based on analysis of historical rate versus time decline curves and P/Z performance plots, supplemented by volumetric calculations of original-gas-in-place (OGIP) using all available well log and 3D seismic data. The reservoir has been effectively drilled to the lowest structural datum and no significant aquifer has been found. Performance to date indicates a depletion drive system.

All Dutch and Mary Rose wells now flow to compression on the 'H' platform, allowing for a decrease in producing flowing tubing pressures. This two-stage compression lowers line pressure to approximately 200 psi. There are no remaining capital or startup costs for compression on the 'H' platform.

Contango's working interest ownership is approximately 55 percent in the Dutch wells and 53 percent in the Mary Rose 1 through 3 wells. The Contango working interest in the Mary Rose 4 and 5 wells is approximately 35 and 38 percent, respectively.

Two wells on the State acreage originally produced from gas reservoirs separate from the main CibOp reservoir. The Eloise 3 well produced and depleted a lower RobL sand and was recompleted to an isolated CibOp sand during the last quarter of 2011. This stray CibOp producer, now called the Mary Rose 5, began producing in January 2012. The Eloise 5 well has also produced and depleted a lower RobL sand and was recompleted to the main CibOp reservoir mid-year 2011. The Eloise 5 was renamed the Dutch 5 well and began producing from the main CibOp reservoir in July 2011.

Vermilion 170

Contango drilled the OCS-G-33596 #1 in March of 2011 and successfully completed the well in the Big A sand at a depth of approximately 13,800 feet. Production started in September 2011 upon installation of a production platform in 87 feet of water. Current production rates are 3.0 MMCF per day with 20 barrels of condensate. Cumulative production to date is approximately 23.9 BCF of gas and 462 MBBL of condensate. Proved producing reserves are based on analysis of the gas rate versus time production history for the well. The well was sold effective December 1, 2018. Contango retains an 8.724 percent overriding royalty interest.

Tuscaloosa Marine Shale Wells

Contango owns a working interest in three Tuscaloosa Marine Shale (TMS) wells drilled from 2012 to 2014, which are operated by Goodrich Petroleum. The wells are located in Wilkinson and Amite Counties, Mississippi, and they produce from the Cretaceous aged TMS at a true vertical depth of approximately 12,000 feet. The wells were drilled horizontally with variable lateral lengths that average approximately 6,000'. The wells were hydraulically fracture stimulated to increase well deliverability. Peak oil rates for the wells ranged from 225 to 875 BBL of oil per day, and averaged 585 BBL of oil per day. The wells are on hydraulic pump with a current combined rate of approximately 35 BBL of oil per day. Cumulative oil production to date is approximately 396 MBBL. There are currently no gas sales for the TMS wells.

Pecos County Wolfcamp Wells

During 2017, Contango embarked on a drilling program for Wolfcamp Shale wells in Pecos County, Texas. Twelve wells have been drilled and completed and are carried as proved developed producing (PDP) in this report. The twelve wells have a combined producing rate of approximately 2,390 BOPD and 5,130 MCFPD. Cumulative production to date is approximately 1,116 MBBL and 2,204 MMCF.

Reserves for the twelve wells are based on analysis of all available daily rate data from the wells. Proved undeveloped (PUD) locations are assigned to each to lease such that there are six wells total per lease. Reserves were assigned to the PUD locations using the average EUR from the proved developed producing (PDP) wells and a type curve developed from an analysis of the PDP wells and offsetting wells in the surrounding leases.

OIL AND GAS PRICING

Projections of proved reserves contained in this report utilize constant product prices of $3.10 per MMBTU of gas and $65.56 per barrel of oil. These are the average first-of-month prices for the prior 12-month period for Henry Hub gas and West Texas Intermediate (WTI) oil. Appropriate oil and gas pricing differentials, residue gas shrink, NGL yields, and NGL pricing as a fraction of WTI were calculated for each field, as shown below in Table 2.

TABLE 2

CONTANGO – PRODUCT PRICE DIFFERENTIALS AND NGL YIELD BY FIELD

Field	Oil/Cond Differential ($/BBL)	Residue Gas Differential ($/MMBTU)	Residue Gas Fraction after Fuel & NGL	NGL Yield (B/MM)	NGL Fraction of WTI Price
Eugene Island 10 (DMR)	0.757	0.019	0.8633	30.883	0.497
Vermilion 170	2.164	-0.359	0.8936	17.406	0.553
Pecos County Wolfcamp	-3.658	-0.471	0.4658	84.042	0.388
TMS	1.523				

OPERATING COSTS

Future operating costs for each of the Contango wells are held constant at current values for the life of the property. These costs were calculated using 12-month lease operating expense (LOE) statements provided by Contango. Following is a brief description of the gross operating cost projections for each of the Contango properties:

According to the data analyzed, the seven producing Eugene Island 10 wells, including the Dutch 1-5 and Mary Rose 1 and 2 wells, had an average monthly operating cost of $727,366, or $95,194 per producing well. These wells produce to the 'H Platform' and are subject to product transportation and processing fees. Transportation and processing fees of $0.001 per net produced MCF, $1.153 per net barrel of oil, and $2.080 per net barrel of NGL were scheduled.

For Vermilion 170, a fixed monthly operating cost of $150,206 was scheduled. Transportation and processing fees of $0.078 per net MCF of produced gas, $2.790 per net barrel of oil, and $7.461 per net barrel of NGL were also scheduled.

A fixed monthly operating cost of $20,584 per well was scheduled for each Tuscaloosa Marine Shale well.

A per well monthly operating cost of $13,764 was scheduled for the Pecos County Wolfcamp wells. Additionally, variable operating costs of $2.445 per barrel oil and $0.408 per MCF were scheduled. Transportation and processing costs of $0.743 per net produced MCF and $3.712 per net produced barrel of NGL were also scheduled.

CAPITAL COSTS

There are no future development projects scheduled for the Contango offshore properties. However, abandonment costs, as provided by Contango, have been scheduled. Platform abandonment costs are net of anticipated salvage value. No salvage value for the individual wells has been considered.

The development costs for each Pecos County PUD location was scheduled at 9.5 million dollars. This value was provided by Contango, and is consistent with our experience in the area.

PROFESSIONAL GUIDELINES

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years, from known reservoirs under expected economic and operating conditions. Reserves are considered proved if economic productivity is supported by either actual production or conclusive formation tests.

Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves, but more certain to be recovered than possible reserves. Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

The reserve definitions used by Cobb & Associates are consistent with definitions set forth in the PRMS and approved by the Society of Petroleum Engineers and other professional organizations.

The reserves included in this report are estimates only and should not be construed as being exact quantities. Governmental policies, uncertainties of supply and demand, the prices actually received for the reserves, and the costs incurred in recovering such reserves, may vary from the price and cost assumptions in this report. Estimated reserves using price escalations may vary from values obtained using constant price scenarios. In any case, estimates of reserves, resources, and revenues may increase or decrease as a result of future operations.

Cobb & Associates has not examined titles to the appraised properties nor has the actual degree of interest owned been independently confirmed. The data used in this evaluation were obtained from Contango Oil & Gas Company and the non-confidential files of Cobb & Associates and were considered accurate.

We have not made a field examination of the Contango properties, therefore, operating ability and condition of the production equipment have not been considered. Also, environmental liabilities, if any, caused by Contango or any other operator have not been considered, nor has the cost to restore the property to acceptable conditions, as may be required by regulation, been taken into account.

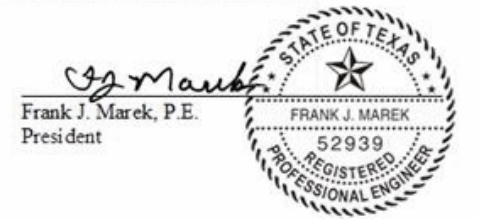
In evaluating available information concerning this appraisal, Cobb & Associates has excluded from its consideration all matters as to which legal or accounting interpretation, rather than engineering, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and conclusions necessarily represent only informed professional judgments.

William M. Cobb & Associates, Inc. is an independent consulting firm founded in 1983. Its compensation is not contingent on the results obtained or reported. Frank J. Marek, a Registered Texas Professional Engineer and President of William M. Cobb & Associates, Inc., is primarily responsible for overseeing the preparation of the reserve report. His professional qualifications meet or exceed the qualifications of reserve estimators set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include: Bachelor of Science degree in Petroleum Engineering from Texas A&M University 1977; member of the Society of Petroleum Engineers; member of the Society of Petroleum Evaluation Engineers; and 40 years of experience in estimating and evaluating reserve information and estimating and evaluating reserves.

Cobb & Associates appreciates the opportunity to be of service to you. If you have any questions regarding this report, please do not hesitate to contact us.

Sincerely,

WILLIAM M. COBB & ASSOCIATES, INC.
Texas Registered Engineering Firm F-84



Frank J. Marek, P.E.
President

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

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CHAIRMAN & CEO: C.H. (SCOTT) REES III
PRESIDENT & COO: DANNY D. SIMMONS
EXECUTIVE VP: G. LANCE BINDER

February 11, 2019

Ms. Christie Schultz
Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, Texas 77002

Dear Ms. Schultz:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2018, to the Contango Oil & Gas Company (Contango) interest in certain oil and gas properties located in Louisiana, Mississippi, Texas, and Wyoming. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 18 percent of all proved reserves owned by Contango. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, except that future income taxes are excluded for all properties and, as requested, per-well overhead expenses are excluded for the operated properties and abandonment costs have not been included in our estimates of future net revenue. Definitions are presented immediately following this letter. This report has been prepared for Contango's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Contango interest in these properties, as of December 31, 2018, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	986.0	407.2	3,962.5	39,877.1	27,599.1
Proved Developed Non-Producing	6.7	69.0	1,224.7	2,183.0	1,580.5
Proved Undeveloped	1,050.1	215.6	1,796.0	27,758.5	14,065.3
Total Proved	2,042.9	691.8	6,983.2	69,818.7	43,244.9

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Contango's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Contango's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the

value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2018. For oil and NGL volumes, the average West Texas Intermediate posted price of $62.04 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.100 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $65.88 per barrel of oil, $23.42 per barrel of NGL, and $2.865 per MCF of gas.

Operating costs used in this report are based on operating expense records of Contango. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties include only direct lease- and field-level costs. Operating costs have been divided into per-well costs and per-unit-of-production costs. For all properties, headquarters general and administrative overhead expenses of Contango are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Contango and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Contango interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Contango receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Contango, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Contango, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Chad E. Ireton, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2012 and has over 11 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Chad E. Ireton
Chad E. Ireton, P.E. 115760
Vice President

Date Signed: February 11, 2019

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 11, 2019

CEI:DEC

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore,

and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain,

regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as 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 or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) 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:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be 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 an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

W.D. Von Gonten&Co.
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January 24, 2019

Mr. John P. Atwood
Senior Vice President
Exaro Energy III, LLC
5850 San Felipe, Suite 500
Houston, Texas 77057

Re: Engineering Evaluation
Estimate of Reserves & Revenues
Year End 2018 SEC Pricing
"As of" January 1, 2019

Dear Mr. Atwood:

At your request, W.D. Von Gonten & Co. has estimated future reserves and projected net revenues attributable to certain oil and gas interests currently owned by Exaro Energy III, LLC (Exaro). The properties represented herein are located in the Jonah field of Sublette County, Wyoming. A summary of the discounted future net revenue attributable to Exaro's Proven reserves, "As of" January 1, 2019, is as follows:

SEC Year End 2018 Pricing	*Net to Exaro Energy III, LLC*			
	Proved Developed Producing			Total Proved
	New Wells	Old Wells	Total	
Reserve Estimates				
Oil/Cond., Mbbl	365.3	370.5	735.8	735.8
Gas, MMcf	28,132.9	39,485.6	67,618.5	67,618.5
Gas Equivalent, MMcfe	30,324.5	41,708.8	72,033.3	72,033.3
Revenues				
Oil, $ (18.8)%	23,209,134	23,561,988	46,771,120	46,771,120
Gas, $ (81.2)%	86,677,568	115,166,752	201,844,304	201,844,304
Total, $	109,886,702	138,728,740	248,615,424	248,615,424
Expenditures				
AdValorem Taxes, $	4,422,786	6,647,802	11,070,587	11,070,587
Severance Taxes, $	4,582,276	7,089,037	11,671,314	11,671,314
Direct Operating Expense, $	29,223,600	50,320,528	79,544,136	79,544,136
Variable Operating Expense, $	19,723,904	28,169,525	47,893,426	47,893,426
Total, $	57,952,566	92,226,892	150,179,463	150,179,463
Investments				
Capital, $	1,656,183	4,485,107	6,141,290	6,141,290
Estimated Future Net Revenues(FNR)				
Undiscounted FNR, $	50,277,960	42,016,696	92,294,672	92,294,672
FNR Disc. @ 10%, $	28,999,520	27,879,950	56,879,476	56,879,476
Allocation Percentage by Classification				
FNR Disc. @ 10%, $	51.0%	49.0%	100.0%	

*Due to computer rounding, numbers in the above table may not sum exactly.

Report Preparation

Purpose of Report – The purpose of this report is to provide Exaro with a projection of future reserves and revenues attributable to certain Proved oil and gas interests presently owned.

Scope of Report – W.D. Von Gonten & Co. was engaged by Exaro to estimate the reserves and revenues associated with the properties included in this report. Once reserves were estimated, future revenue projections were generated utilizing SEC pricing guidelines.

Reporting Requirements – Securities and Exchange Commission (SEC) Regulation S-X 210, Rule 4-10 and Regulation S-K 229, Item 1200 (as revised in December 2008, effective 1-1-10), and Financial Accounting Standards Board (FASB) Statement No. 69 require oil and gas reserve information to be reported by publicly held companies as supplemental financial data. These regulations and standards provide for estimates of Proved reserves and revenues discounted at 10% and based on unescalated prices and costs. Revenues based on alternate product price scenarios may be reported in addition to the current pricing case. Reporting probable and possible reserves is optional. Probable and possible reserves must be reported separately from proved reserves.

The Society of Petroleum Engineers (SPE) requires Proved reserves to be economically recoverable with prices and costs in effect on the "as of" date of the report. In conjunction with the World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), the SPE has issued *Petroleum Resources Management System* (**2007 ed.**), which sets forth the definitions and requirements associated with the classification of both reserves and resources. In addition, the SPE has issued *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information,* which sets requirements for the qualifications and independence of reserve estimators and auditors.

The estimated Proved reserves herein have been prepared in conformance with all SEC, SPE, WPC, AAPG, and SPEE definitions and requirements.

Projections – The reserve and revenue projections represented herein are on a calendar year basis, with the first time period beginning January 1, 2019 and ending December 31, 2019.

Property Discussion

Exaro signed an Earning and Development Agreement (EDA) with Encana Oil & Gas (Encana) in April 2012 that allowed them to gradually obtain increasing levels of ownership in the Jonah field. As part of the EDA, Exaro's interest in each well drilled prior to the April 2012 agreement (old Proved Developed Producing (PDP) wells) continued to increase as Encana drilled additional wells (new wells) within the field. Exaro's interest in the new wells stayed constant for the life of the well. For each new well drilled within the EDA, Exaro paid for 100% of the capital costs and earned 32.5% of Encana's interest in the new wellbore until Exaro was fully earned into their devoted interest. In addition, for each new well drilled, Exaro earned 0.40% interest in the old PDP wells and related leasehold if Encana's working interest in the new well location was 100% and a proportional share if not.

As of the date of this report, Encana has sold its ownership to Jonah Energy, LLC (Jonah Energy). Exaro notified Jonah Energy of its intent to terminate the EDA effective May 12, 2014, and thereafter participate under the existing Joint Operating Agreements (JOA's) going forward. Exaro currently has no locations left under the EDA. All wells are proposed under the JOA and Exaro has the right to participate for its working interest in each well. At the current time, there are no rigs running within Exaro's acreage.

Production in this area is primarily from the Lance sand which can range from 8,000' to 11,000' in depth and approach 3000' in interval thickness.

Beginning in 2014, Jonah Energy began drilling horizontal wells across the eastern sections of Exaro's acreage. To date, there are six horizontal wells currently producing.

Starting in February 2015, Jonah Energy began line pressure reduction projects in the field on varying groups of wells. They started by lowering the pressure from 200 psi to 50 psi in 17 wells located in section 35. Lowering the pressure caused an increase in the production rate and reserves on most of the connected wells. Based on provided daily production data, W.D. Von Gonten & Co. was able to give these wells a brief uplift in the production projections. Jonah Energy has since begun and maintained several similar projects throughout Exaro's acreage.

Figure 1 displays the comparison of Exaro's historical monthly net production and W.D. Von Gonten & Co.'s forecasted net monthly production beginning January 1, 2019.

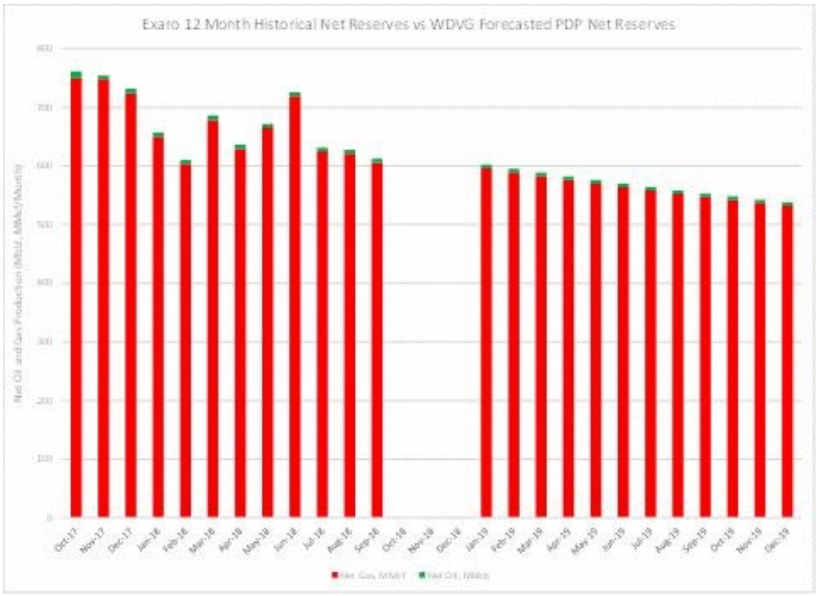

Figure 1: Historical Net Production and PDP Reserves Forecast as of January 1, 2019

Figure 2 below is a graphical comparison of Exaro's October 2017 through September 2018 historical net revenue and W.D. Von Gonten & Co.'s forecasted net revenue beginning January 1, 2019.

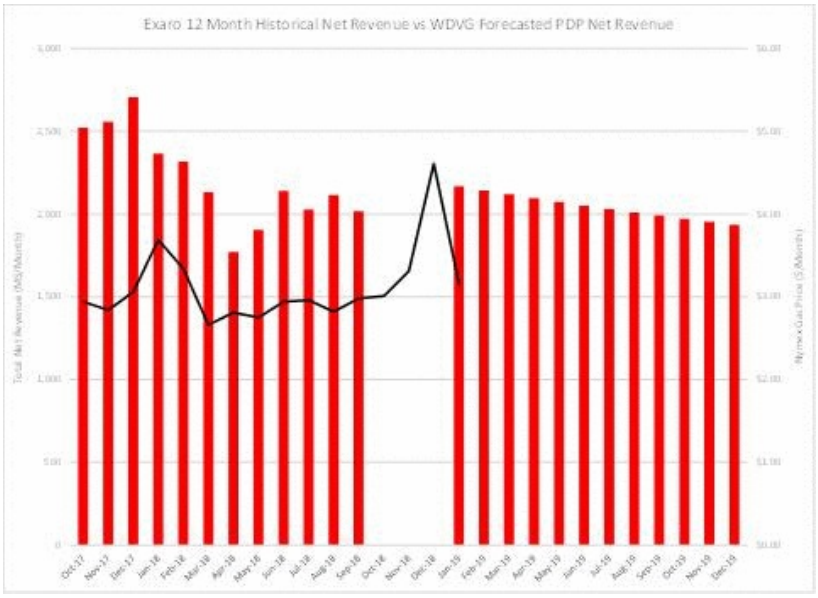

Figure 2: Historical Net Revenue and Forecasted Net Revenue as of January 1, 2019

Reserves Discussion

Reserves estimates represented herein were generally determined through the implementation of various methods including, but not limited to, performance decline, analogy, and type curve analysis. Based on the amount of available data, one or more of the above methods was utilized as deemed appropriate.

Reserves and schedules of production included in this report are only estimates. The amount of available data, reservoir and geological complexity, reservoir drive mechanism, and mechanical aspects can have a material effect on the accuracy of these reserve estimates. Due to inherent uncertainties in future production rates, commodity prices, and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom, and/or the actual costs incurred could be more or less than the estimated amounts.

Product Prices Discussion

SEC pricing is determined by averaging the first day of each month's closing price for the previous calendar year using published benchmark oil and gas prices. This method, as applied for the purposes of this report, renders a price of $65.66 per barrel of oil and $3.16 per MMBtu of gas. These prices were held constant throughout the life of the properties as per SEC guidelines.

Pricing differentials were applied on a field basis to reflect the actual prices received at the wellhead. Differentials typically account for transportation costs, geographical differentials, marketing bonuses or deductions, and any other factors that may affect the prices actually received at the wellhead. W.D. Von Gonten & Co. determined the historical pricing differentials from lease operating data provided by Exaro representing the time period October 2017 through September 2018.

Figures 3 and 4 illustrate the comparison between historical differentials versus what is being projected.

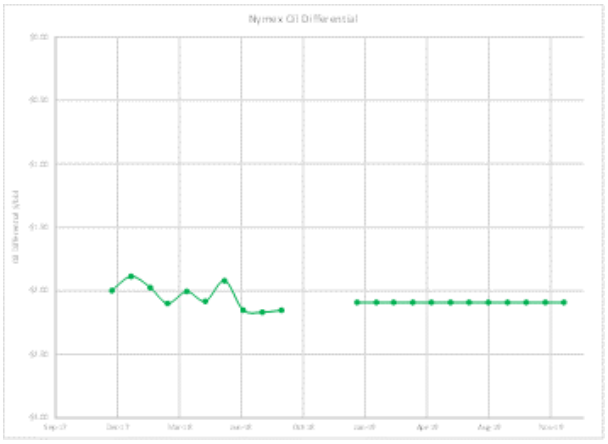

Figure 3: Historical and Forecasted Oil Differential

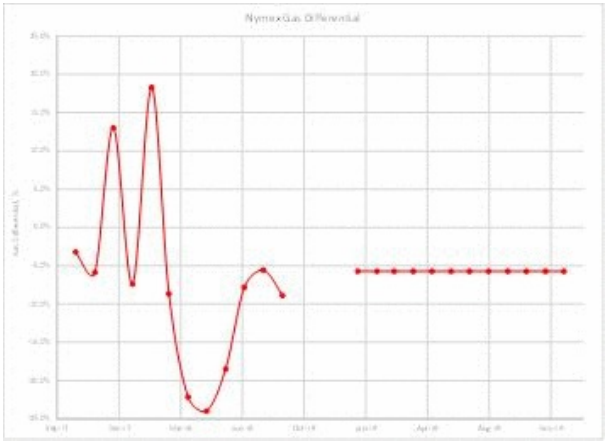

Figure 4: Historical and Forecasted Gas Differential

W.D. Von Gonten & Co. has included the historical NGL revenue and processing fees within the gas price differential for the new wells only. Due to existing and new contracts, the old wells do not include any NGL revenues or fees.

Operating Expenses and Capital Costs Discussion

Projected monthly operating expenses associated with the Jonah properties were based on the review of lease operating data provided by Exaro for the time period October 2017 through September 2018. Using the supplied data, W.D. Von Gonten & Co. applied a gross direct expense to each well based on its classification of either “new” or “old”. If the well was involved in a line pressure reduction project, the operating expenses include additional fees. The horizontal wells also have an increased monthly expense compared to vertical wells based on historical observations. A gross variable deduct of $0.46 per Mcf, which covers gathering fees, has been applied to all wells. In addition, a gross $3.84/bbl salt water disposal (SWD) expense has been applied to each well. All direct and variable operating expenses were held constant for the economic life of each property.

Figure 5 below is a graphical comparison of historical net lease operating expenses for October 2017 through September 2018 versus comparable forecasted expenses for the subsequent twelve months. October 2017 is irregularly high due to property taxes.

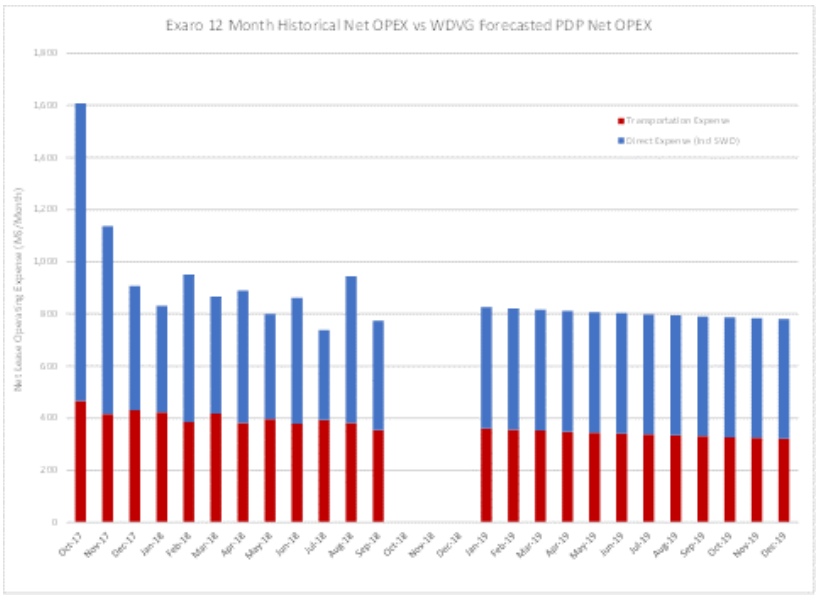

Figure 5: Historical and Forecasted Lease Operating Expense

There are no capital costs associated with any of the properties included herein. Currently Exaro has no knowledge of anticipated work efforts scheduled by the operator.

Other Considerations

Abandonment Costs – Cost estimates regarding future plugging and abandonment liabilities associated with these properties were supplied by Exaro for the purposes of this report. As we have not inspected the properties personally, W.D. Von Gonten & Co. expresses no warranties as to the accuracy or reasonableness of these assumptions. A third party study would be necessary in order to accurately estimate all future abandonment liabilities.

Data Sources – Data furnished by Exaro included basic well information, lease operating statements, ownership, pricing, and production information on certain leases. IHS Energy archives was utilized to view the monthly production for some of the wells included in this report.

Context – We specifically advise that any particular reserve estimate for a specific property not be used out of context with the overall report. ***The revenues and present worth of future net revenues are not represented to be market value either for individual properties or on a total property basis.***

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the estimated oil and gas volumes represented herein. The reserves in this report can be produced under current regulatory guidelines. Actual future commodity prices may differ substantially from the utilized pricing scenario which may or may not extend or limit the estimated reserve and revenue quantities presented in this report.

We have not inspected the properties included in this report, nor have we conducted independent well tests. W.D. Von Gonten & Co. and our employees have no direct ownership in any of the properties included in this report. Our fees are based on hourly expenses, and are not related to the reserve and revenue estimates produced in this report.

Thank you for the opportunity to assist Exaro Energy III, LLC with this project.

W.D. Von Gonten&Co.
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Respectfully submitted,

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