ABRAXAS PETROLEUM CORP
Form 10-K
March 15, 2019

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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

Commission File Number 001-16071

ABRAXAS PETROLEUM CORPORATION

(Exact name of Registrant as specified in its charter)

Nevada	**74-2584033**
(State or Other Jurisdiction of	(I.R.S. Employer Identification Number)

Incorporation or Organization)

18803 Meisner Drive

San Antonio, TX 78258

(Address of principal executive offices)

(210) 490-4788

Registrant's telephone number, including area code

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class:	**Name of each exchange on which registered:**
Common Stock, par value $.01 per share	The NASDAQ Stock Market, LLC

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 Exchange Act.

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 if the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Yes No

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

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

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

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

As of June 30, 2018, the last day of the registrant’s most recently completed second fiscal quarter, the aggregate market value of the common stock held by non-affiliates of the registrant was $470,774,656 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 8, 2019, there were 166,934,860 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant’s Proxy Statement relating to the 2019 Annual Meeting of Stockholders to be held on May 7, 2019.	Part III

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We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe,” “expect,” “anticipate,” “intend,” “will,” “plan,” “may,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report is generally located in the material set forth under the headings “Business,” “Properties,” “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- the prices we receive for our production and the effectiveness of our hedging activities;
- the availability of capital including under our credit facility;
- our success in development, exploitation and exploration activities;
- declines in our production of oil and gas;
- our indebtedness and the significant amount of cash required to service our indebtedness,
- the proximity, capacity, cost and availability of pipelines and other transportation facilities,
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by our credit facility and restrictive debt covenants;
- our ability to make planned capital expenditures;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and gas prices;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our ability to procure services and equipment for our drilling and completion activities;

- our acquisition and divestiture activities;
- weather conditions and events; and
- other factors discussed elsewhere in this report.

Initial production, or IP, rates, for both our wells and for those wells that are located near our properties, are limited data points in each well’s productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery, or EUR, or economic rates of return from such wells and should not be relied upon for such purposes. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Abraxas standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

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GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

"***Bbl***" – barrel or barrels.

"***Bcf***" – billion cubic feet of gas.

"***Bcfe***" – billion cubic feet of gas equivalent.

"***Boe***" – barrels of oil equivalent.

"***Boepd*****"** - barrels of oil equivalents per day.

"***MBbl***" – thousand barrels.

*"**MBoe**"* **–** thousand barrels of oil equivalent.

"***Mcf***" – thousand cubic feet of gas.

"***Mcfe***" – thousand cubic feet of gas equivalent.

"***MMBbl***" – million barrels.

"MMBoe" – million barrels of oil equivalent.

"***MMBtu***" – million British Thermal Units of gas.

"***MMcf***" – million cubic feet of gas.

"***MMcfe***" – million cubic feet of gas equivalent.

***"NGL"* –** natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

"***Developed acreage***" means acreage which consists of leased acres spaced or assignable to productive wells.

"***Development well***" is a well drilled within the proved area of an oil or gas reservoir to the depth or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

"***Dry hole***" is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

"***Exploratory well***" is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be producing in another reservoir, or to extend a known reservoir.

"***Gross acres***" are the number of acres in which we own a working interest.

"***Gross well***" is a well in which we own an interest.

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"***Net acres***" are the sum of fractional ownership working interests in gross acres (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

"***Net well***" is the sum of fractional ownership working interests in gross wells.

"***Productive well***" is an exploratory or a development well that is not a dry hole.

"***Undeveloped acreage***" means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

"***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.

"Proved developed non-producing reserves*" are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that 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 recompletion prior to the start of production.

"Proved developed reserves*" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"***Proved reserves****" Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves" *or* ***"PUDs*"*** Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

"***PV-10***" means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission ("SEC"). PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

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"***Standardized Measure***" means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation or de-escalation, calculated in accordance with Accounting Standards Codification ("ASC") 932, "Disclosures About Oil and Gas Producing Activities."

"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.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see:
http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.21

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Part I

Information contained in this report represents the consolidated operations of Abraxas Petroleum Corporation. The terms “Abraxas,” “we,” “us,” “our,” or the “Company,” refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Raven Drilling, LLC which is a wholly owned subsidiary that owns a drilling rig. Unless otherwise noted, all disclosures are for Continuing Operations.

Item 1. Business

General

We are an independent energy company primarily engaged in the acquisition, exploration, development and production of oil and gas. At December 31, 2018, our estimated net proved reserves were 67.2 MMBoe, of which 37% were classified as proved developed, 63% were oil and 96% of which (on a Boe basis) were operated by us. Our daily net production for the year ended December 31, 2018 was 9,809 Boepd, of which 64% was oil. Abraxas Petroleum Corporation was incorporated in Nevada in 1990. Our address is 18803 Meisner Drive, San Antonio, Texas 78258 and our phone number is (210) 490-4788.

Our oil and gas assets are located in three operating regions, the Permian/Delaware Basin, the Rocky Mountain, and South Texas. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2018:

				Estimated Net Proved Reserves		Net Production	
	Gross Producing Wells	Average Working Interest	Total Net Acres	(Mboe)	% Oil	(Mboe)	% Oil
Permian/Delaware Basin	115	74.44 %	23,617	41,058	61 %	1,328	64 %
Rocky Mountain	539	13.80 %	20,616	24,331	68 %	2,040	66 %
South Texas	24	96.88 %	12,959	1,839	27 %	212	57 %
Total United States	678	28.08 %	57,192	67,228	63 %	3,580	58 %

Our properties in the Permian/Delaware Basin region are primarily located in Ward and Winkler Counties, Texas and produce oil and gas primarily from the Bone Spring and Wolfcamp formations.

Our properties in the Rocky Mountain region are primarily located in the Williston Basin of North Dakota and Montana. In this region, our wells produce oil and gas from various reservoirs, primarily the Bakken, Three Forks and Red River formations.

Our properties in the South Texas region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas and the Eagle Ford shale and the Austin Chalk in Atascosa County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation.

Strategy

Our business strategy is to focus our capital and resources on our core operated basins, improve financial flexibility and profitably grow production and reserves. Key elements of our business strategy include:

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Focus our capital and resources on our core operated basins. Our core basins consist of the Permian/Delaware Basin (Bone Spring and Wolfcamp) and Williston Basin (Bakken and Three Forks). Given the disparity which has existed during the past several years and which continues currently between oil and gas prices, the economics of drilling oil wells is far superior to drilling gas wells. We anticipate making capital expenditures in 2019 of approximately $94.5 million, of which approximately $46.2 million is allocated to acquiring additional acreage and developing our Bone Spring/Wolfcamp properties in the Permian/Delaware Basin. The 2019 budget also allocates approximately $38.3 million for developing our Williston Basin/Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. As part of our efforts to focus our property portfolio, we also seek to sell assets we have deemed non-core. These include assets with a low working interest that are non-operated and/or that fall outside of our three core basins. Any proceeds from these asset sales have been and will continue to be used to reduce our indebtedness and/or be redeployed into our core operating basins. We are currently actively working to monetize our remaining Eagle Ford assets in South Texas.

Improve financial flexibility. Our primary sources of capital are availability under our credit facility and cash flows from operations. Availability under our credit facility is subject to a borrowing base which is determined semi-annually by our lenders. The next redetermination is scheduled for April 2019. As of December 31, 2018, we had $180.0 million outstanding on our credit facility and availability of $20.0 million, and we generated approximately $80.0 million of cash flows from operations.

We have also sold producing properties from time to time in order to provide us with financial flexibility. In December 2018 and January 2019, we sold various Eagle Ford assets in our South Texas region for approximately $1.6 million and are currently marketing our remaining Eagle Ford assets. In January 2019, we announced that we had engaged Petrie Partners to assist us in identifying and assessing our options for our Bakken properties. We are still early in this process and do not know the ultimate outcome. In the event that this process were to result in the sale of our Bakken properties, we believe that the proceeds would be used to significantly pay down or fully retire our debt, support our Raven No. 1 rig in the Delaware Basin until it achieves free cash flow and possibly buy back stock.

We seek to reduce the volatility of our cash flows from operations by hedging a portion of our production. As of December 31, 2018, we had NYMEX-based fixed price commodity swap arrangements, on approximately 51% of the oil production from our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021.

During 2018, we had originally established a capital budget of $140.0 million. Capital spending for 2018 was $174.0 million. We exceeded our 2018 capital budget as a result of successfully acquiring more acreage in the Delaware Basin than we had originally budgeted which resulted in increased spending for acquisitions as well as for drilling and completing wells in this area as a result of our higher ownership interests.

We intend to maintain our liquidity and our balance sheet during 2019 by adjusting our capital budget as necessary, seeking to reduce expenses and by funding our capital budget primarily with cash flow from operations.

Profitably grow production and reserves. We have a substantial low-decline legacy production base as evidenced by our approximate 21-year average reserve life as of year-end 2018. Our capital is currently being deployed largely into unconventional oil assets with relatively predictable production profiles, yet steep initial decline rates. Therefore, the economics of these oil wells are highly dependent on both near term commodity prices and strong operational cost control. Cost savings achieved through efficiencies of using our own rig in the Williston Basin, and heightened focus on cost control in all of our operated positions both contribute to our historical success in adding low cost barrels to our production base.

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2019 Budget and Drilling Activities

Our capital expenditure budget for 2019 is approximately $94.5 million of which approximately $46.2 million is allocated to acquiring additional acreage and developing the Company's Bone Spring/Wolfcamp acreage in the Permian/Delaware Basin. The budget also allocates approximately $38.3 million to developing our Williston Basin Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. The 2019 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources including under our credit facility, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, our financial results and our ability to obtain permits for drilling locations.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the world wide economy (particularly the manufacturing sector), foreign imports, political conditions in other petroleum producing countries, the actions of the Organization of Petroleum Exporting Countries, domestic regulation, legislation and policies. Decreases in the prices we receive for our oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, our revenue, profitability and cash flow from operations. Refer to "Risk Factors – Risks Related to Our Industry — Market conditions for oil and gas and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows from operations, profitability and growth" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies" for more information relating to the effects that decreases in oil and gas prices have on us. To help mitigate the impact of commodity price volatility, we hedge a portion of our production through the use of fixed price swaps and basis differential swap contracts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Hedging Arrangements" and Note 11 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2018, two purchasers of production accounted for approximately 57% of our oil and gas sales. During the year ended December 31, 2017, three purchasers of production accounted for approximately 69% of our oil and gas sales and in 2016, two purchasers accounted for approximately 71% of our oil and gas sales. We believe that there are numerous other purchasers available to buy our oil and gas and that the loss of any of these purchasers would not materially affect our ability to sell our oil and gas. Furthermore, the largest purchasers of our oil and gas have changed from year to year from 2016 to 2018.

Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our properties are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental and other laws relating to the petroleum industry, and by changes in such laws and by periodically changing administrative regulations.

Federal, state and local laws and regulations govern oil and gas activities. Operators of oil and gas properties are required to have a number of permits in order to operate such properties, including operator permits and permits to dispose of salt water. In addition, under federal law, operators of oil and gas properties are required to possess certain certificates and permits in order to operate such properties. We possess all material requisite permits required by Federal, state and other local authorities in which we operate properties.

Development and Production

The operations of our properties are subject to various types of regulation at the federal, state and local levels. These types of regulations include requiring the operator of oil and gas properties to possess permits for the drilling and development of wells, post bonds in connection with various types of activities, and file reports concerning operations. Most states, and some counties and municipalities in which we operate, regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the flaring of gas;
- the method of completing and fracture stimulating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

Some states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some states allow forced pooling or unitization of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, gas and NGLs within its jurisdiction.

Operations on Federal or Indian oil and gas leases must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various tribal and federal agencies, including the Bureau of Land Management and the Office of Natural Resources Revenue, which we refer to as ONRR, (formerly Minerals Management Service). ONRR establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by ONRR and the state regulatory authorities is generally applicable to all federal and state oil and gas leases. Accordingly, we believe that the impact of royalty regulation on the operations of our properties should generally be the same as the impact on our competitors. We believe that the operations of our properties are in material compliance with all applicable regulations as they pertain to Federal or Indian oil and gas leases.

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The failure to comply with these rules and regulations can result in substantial penalties, including lease suspension or termination in certain cases. The regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect us.

Regulation of Transportation and Sale of Gas in the United States

Historically, the transportation and sale for resale of gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended, which we refer to as NGA, the Natural Gas Policy Act of 1978, as amended, which we refer to as NGPA, and regulations promulgated thereunder by the Federal Energy Regulatory Commission, which we refer to as FERC, and its predecessors. In the past, the federal government has regulated the prices at which gas could be sold. Deregulation of wellhead gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended, which we refer to as the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of gas effective January 1, 1993. While sales by producers of gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

Since 1985, FERC has endeavored to make gas transportation more accessible to gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate gas pipeline industry and to create a regulatory framework that will put gas sellers into more direct contractual relations with gas buyers by, among other things, unbundling the sale of gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders, which we refer to collectively as Order No. 636, to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell gas. FERC continues to regulate the rates that interstate pipelines may charge for such transportation and storage services. Although FERC's orders do not directly regulate gas producers, they are intended to foster increased competition within all phases of the gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders, which we refer to, collectively, as Order No. 637, which imposed a number of additional reforms designed to enhance competition in gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Energy Policy Act of 2005, which we refer to as EP Act 2005, gave FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended the NGA to prohibit market manipulation and also amended the NGA and the NGPA to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of FERC to up to $1,000,000 per day, per violation. In addition, FERC issued a final rule effective January 26, 2006, regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of gas or transportation service subject to FERC jurisdiction, to defraud, make an untrue statement, or omit a material fact or engage in any practice, act, or course of business that operates or would operate as a fraud. This final rule works together with FERC's enhanced penalty authority to provide increased oversight of the gas marketplace.

The gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach currently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other gas producers, gatherers and marketers.

Generally, intrastate gas transportation is subject to regulation by state regulatory agencies, although FERC does regulate the rates, terms, and conditions of service provided by intrastate pipelines that transport gas subject to FERC's NGA jurisdiction pursuant to Section 311 of the NGPA. The basis for state regulation of intrastate gas transportation and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate gas transportation in any states in which we operate and ship gas on an intrastate basis will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

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Gas Gathering in the United States

Section 1(b) of the NGA exempts gas gathering facilities from the jurisdiction of the FERC. FERC has developed tests for determining which facilities constitute jurisdictional transportation facilities under the NGA and which facilities constitute gathering facilities exempt from FERC's NGA jurisdiction. From time to time, FERC reconsiders its test for defining non-jurisdictional gathering. FERC has also permitted jurisdictional pipelines to "spin down" exempt gathering facilities into affiliated entities that are not subject to FERC jurisdiction, although FERC continues to examine the circumstances in which such a "spin down" is appropriate and whether it should reassert jurisdiction over certain gathering companies and facilities that previously had been "spun down." We cannot predict the effect that FERC's activities in this regard may have on the operations of our properties, but we do not expect these activities to affect the operations in any way that is materially different from the effect thereof on our competitors.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service requirements, but does not generally entail rate regulation. In the United States, gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under FERC Order 636. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the state's more active review of rates, services and practices associated with the gathering and transportation of gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

Regulation of Transportation of Oil in the United States

Sales of oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, FERC, in February 2003, increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulations, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

All of our oil is sold on lease, at which time custody transfers, either by truck or pipeline. We are not able to determine how much of our sold oil is ultimately shipped to market centers using rail transportation facilities owned and operated by third parties. The U.S. Department of Transportation's ("U.S. DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") establishes safety regulations relating to transportation of oil by rail transportation. In addition, third party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the U.S. DOT, the Federal Railroad Administration ("FRA") of the DOT, the U.S. Occupational Safety and Health Administration, as well as other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and seek to regulate movement of hazardous materials in ways not preempted by federal law.

In response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. Recently, in response to train derailments occurring in 2013, U.S. regulators have been implementing or considering new rules to address the safety risks of transporting oil by rail. On January 23, 2014, the National Transportation Safety Board ("NTSB") issued a series of recommendations to the FRA and PHMSA to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) developing an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) auditing shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the DOT issued an emergency order requiring all persons, prior to offering oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of oil be handled as a Packing Group I or II hazardous material.

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We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or handling of shipments of oil by rail transportation could increase our costs of doing business and limit our ability to transport and sell our oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows from operations. At this time, it is not possible to estimate the potential impact on our business if new federal or state rail transportation regulations are enacted.

Environmental Matters

Oil and gas operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, treatment, storage and disposal of materials and the discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences;
- impose design, construction and permitting requirements on facilities in conjunction with oil and gas operations, including the construction of pollution control devices;
- require protective measures to prevent certain fluids from coming into contact with ground water;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, and gas processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and areas inhabited by threatened or endangered species and other protected areas;
- require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells;
- require disclosure of chemicals injected into wells in conjunction with hydraulic fracturing operations;
- restrict injection of liquids into subsurface strata that may contaminate groundwater or increase seismic activity;

- restrict the availability of water necessary for hydraulic fracturing operations;
- impose substantial penalties for violations of environmental rules or pollution resulting from our operations;
- curtail production in association with permit limits; and
- curtail or prohibit production for exceeding gas flaring limits.

Environmental permits that the operators of properties are required to possess may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on our operations as well as the oil and gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

We are not currently involved in any administrative, judicial or legal proceedings arising under federal, state, or local environmental protection laws and regulations, or under federal or state common law, which would have a material adverse effect on our respective financial positions or results of operations. Moreover, we maintain insurance against the costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

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The following is a discussion of the current relevant environmental laws and regulations that relate to our operations.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as CERCLA, and comparable state statutes impose strict joint, and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include among others, the current and former owners or operators of a disposal site or sites where a release occurred and companies that arranged for the transportation or disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable 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. CERCLA authorizes the Environmental Protection Agency ("EPA"), and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment.

In the course of our ordinary operations, certain wastes may be generated that may fall within CERCLA's definition of a "hazardous substance." We may be liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. Although CERCLA contains a "petroleum exclusion" from the definition of "hazardous substance," state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including oil cleanups.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA (as defined below), and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators; to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

Oil Pollution Act of 1990. Federal regulations also require certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The Federal Oil Pollution Act, which we refer to as OPA, and analogous state laws, contain numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on our financial position or results of operations.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid wastes. RCRA imposes stringent requirements and liability for failure to meet such requirements, on persons who generate or transport regulated waste materials and also on persons who own or operate a waste treatment, storage or disposal facility. Analogous state laws also impose requirements associated with the management such wastes. At present, RCRA includes a statutory exemption that allows most oil and gas exploration and production wastes to be classified and regulated as non-hazardous wastes. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and gas exploration and production wastes from regulation as hazardous wastes. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us to incur increased operating expenses. Also, in the ordinary course of our operations, we generate small amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. We believe that our operations comply in all material respects with the requirements of RCRA and its state counterparts.

Naturally Occurring Radioactive Materials, which we refer to as NORM, are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological operations such as mineral extraction or processing through exploration and production conducted by the oil and gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that the operations of our properties are in material compliance with all applicable NORM standards established by the various states in which we operate wells.

Clean Water Act. The Clean Water Act, which we refer to as the CWA, and analogous state laws, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The CWA regulates storm water run-off from oil and gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of the CWA require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a petroleum hydrocarbon tank spill, rupture or leak. The reach and scope of the CWA, and the determination of what water bodies and land areas are regulated as waters of the U.S., is the subject of various rules adopted by EPA and the U.S. Army Corps of Engineers which we refer to as the WOTUS Rules, and on-going federal court litigation arising out of the rules and recent amendments. The WOTUS Rules, litigation over the rules, and the associated regulatory uncertainty, could impact our operations by subjecting new land and waters to regulation, and increase our cost of operations. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for resource damages resulting from the release. We believe that the operations of our properties comply in all material respects with the requirements of the CWA and state statutes enacted to control water pollution.

Safe Drinking Water Act. Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act, which we refer to as the SDWA, and analogous state and local laws. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production., or the flow-back of hydraulic fracturing fluids. The main goal of the SDWA is the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In most states, no underground injection may take place except as authorized by permit or rule. In addition, subsurface injection of water or other produced fluids from drilling or hydraulic fracturing processes have come under increased public and governmental scrutiny. Some jurisdictions, Texas for example, have adopted new and more stringent rules for injection wells aimed at reducing the potential for earthquakes associated with injection activities, including new restrictions on siting of such injection wells. We currently own and operate various underground injection wells and rely on third-party owned injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. More stringent regulations of injection wells could additionally increase our cost of operations. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operation of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. In the past few years, EPA has adopted new more restrictive regulations governing air emissions from oil and gas operations, including regulations which restrict emissions of methane, volatile organic compounds and hazardous air pollutants.

Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas may require us to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to more stringent regulation under the CAA. Failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. We may be required to incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

Hydraulic Fracturing. Most of our current operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand, or other proppants, into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate the formation to enhance production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs, but where these operations occur on federal or tribal lands they are subject to regulation by the U.S. Department of the Interior, Bureau of Land Management (“BLM”). In addition to federal legislative and regulatory actions, some states and local governments have considered imposing, or have adopted various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in hydraulic fracturing, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact the availability of water for hydraulic fracturing. If these types of restrictions are widely adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells, and these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with water wells in the vicinity of an oil or gas well or other alleged environmental problems. Additional information concerning hydraulic fracturing is included under Item 1A "Risk Factors."

Climate Change and Greenhouse Gas Regulation. Scientific studies have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response to these studies, many nations have agreed to limit emissions of “greenhouse gases” or “GHGs” pursuant to efforts spearheaded by the United Nations . Domestically, the Fourth National Climate Assessment report, released in November 2018, noted that climate change is mostly driven by GHG emissions and that climate change is accelerating. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered GHGs. We expect continuing debate, especially in the political arena, over how to address climate change and what policies and regulations are necessary to address the issue. It is possible that domestic and international regulations addressing climate change will have adverse effects on the market for oil, gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, oil, gas and other fossil fuel products. Given widely divergent political views on climate change regulation, we are unable to predict the timing, scope and effect of any proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect our operations, financial condition and results of operations. In addition, several states and local governments have adopted, or are considering adopting, regulations or ordinances to reduce emissions of GHGs. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. The various efforts to regulate the emissions of GHGs (including lawsuits pending in United States federal courts) may affect the cost of our operations, may affect the public’s perception of our industry, and may reduce demand for our products.

An example of the uncertainty in regulations comes from the BLM flaring rule. In November 2016, BLM issued a final rule to further restrict venting and flaring of gas from oil and gas operations on public lands. Then, BLM issued a stay of these requirements in December 2017. In September 2018, BLM published a final rule to modify and rescind substantial portions of the flaring rule. The rescission was challenged by litigation filed in the U.S. District Court for the Northern District of California. If the litigation is successful and the rule restricting flaring of gas were to become effective, we would have to curtail production from the affected wells and would incur additional costs of compliance as well as increased monitoring and recordkeeping for some of our facilities.

Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations. Additional information concerning climate change is included under Item 1A. “Risk Factors.”

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National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of Interior, 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. If we were to conduct any exploration and production activities on federal lands in the future, those activities may need to obtain governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and gas projects and increase the cost of such operations.

Endangered Species Act. The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our properties may be located in areas that may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. Looking forward, we expect more listings of such species to occur, in light of renewed efforts by certain environmental activists to use the ESA as a mechanism to restrict land development and energy production. Such listings could include habitat in areas where we operate or plan to operate, or which could adversely affect our ability to secure needed sand, water or other materials for our operations or to transport oil or gas via pipeline to our customers. Further, some of the species could become subject to voluntary rangeland conservation plans that could affect our operations of sources of materials. Such listing of additional species, or the discovery of previously unidentified endangered or threatened species, or the adoption of conservation plans, could cause us to incur additional costs or become subject to operating restrictions, construction delays, or bans on operating in the affected areas.

Abandonment Costs. All of our oil and gas wells will require proper plugging and abandonment at some time in the future. We have posted bonds with most regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Title to Properties

As is customary in the oil and gas industry, we make only a cursory review of title to undeveloped oil and gas leases at the time we acquire them. However, before drilling commences, we make a thorough title search, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/lessor of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our properties, some of which are subject to immaterial encumbrances, easements and restrictions. The oil and gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.

Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment and services to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our near term operations, we cannot assure you that such materials and resources will be available to us in the future.

Employees

As of March 8, 2019, we had 100 full-time employees. We retain independent geological, land, marketing, engineering and health and safety consultants from time to time and expect to continue to do so in the future.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). You may read and copy any document we file with the SEC at the SEC's public reference room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet web site that contains annual, quarterly and current reports, proxy statements and other information that issuers (including Abraxas) file electronically with the SEC. The SEC's web site is www.sec.gov.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments filed with the SEC are available free of charge on our web site at www.abraxaspetroleum.com in the Investor Relations section as soon as practicable after such reports are filed. Information on our web site is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

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Item 1A. Risk Factors

Risks Related to Our Business

We have substantial indebtedness which may adversely affect our cash flow and business operations.

At December 31, 2018, we had a total of $180.0 million of indebtedness under our credit facility and total indebtedness of $183.4 million (including the current portion). While the amount borrowed under our credit facility at March 8, 2019 was $180.0 million (and total indebtedness was $183.3 million), this amount will likely increase as we pursue drilling and completion of wells. Our indebtedness could have important consequences to us, including:

- affecting our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes which may be impaired or not available on favorable terms;

- requiring us to meet financial tests contained in our credit facility and future debt arrangements that may affect our flexibility in planning for and reacting to changes in our business, including future business opportunities;

- requiring us to use a substantial portion of our cash flow from operations to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and

- making us more vulnerable to competitive pressures if there is a downturn in our business or the economy in general, than our competitors with less debt.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying capital expenditures, acquisitions and/or selling assets, restructuring or refinancing our indebtedness or seeking additional debt or equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of our credit facility, including the inability to comply with the required financial covenants, could result in an event of default. If an event of default occurs (after any applicable notice and cure periods), the lenders would be entitled to terminate any commitment to make further extensions of credit under our credit facility and to accelerate the repayment of amounts outstanding (including accrued and unpaid interest and fees). Upon a default under our credit facility, the lenders could also foreclose against any collateral securing such obligations, which may be all or substantially all of our assets. If that occurred, we may not be able to continue to operate as a going concern. As of December 31, 2018, the Company was in violation of its current ratio covenant under its credit facility. A waiver of this violation has been obtained. We cannot assure you that we will be able to obtain similar waivers in the future.

Depressed oil and/or gas prices would have a material and adverse effect on us.

Our financial results and the value of our properties are highly dependent on the general supply and demand for oil, gas and NGL, which impact the prices we ultimately realize on our sales of these commodities. Oil, gas and NGL prices have been more volatile since the second half of 2014, when there was a significant decline in oil, gas and NGL prices, which adversely affected our operating results and contributed to a reduction in our anticipated future capital expenditures. Prices improved in 2017 and 2018 before declining in the last quarter of 2018. In addition to the impact on our results of operations, declines in oil and gas prices could cause us to write down the value of our estimated proved reserves. For example, the decline in commodity prices prior to 2017 adversely impacted our estimated proved reserves and resulted in a proved property impairment of $67.6 million in 2016. We could record impairments in future periods, the amount of which will be dependent upon many factors such as future prices of oil, gas and NGL, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions.

While oil and gas prices began to improve in late 2016 and remained at somewhat improved levels in 2017 and 2018, prices have remained relatively low and price volatility has continued. A sustained weakness or further deterioration in commodity prices could materially and adversely impact our business by resulting in, or exacerbating, the following effects:

- reducing the amount of oil, gas and NGL that we can produce economically;

- reducing the borrowing base of our credit facility;

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- limiting our financial flexibility, liquidity and access to sources of capital, such as equity and debt;
- reducing our revenues, cash flows from operations and profitability;
- causing us to decrease our capital expenditures or maintain reduced capital spending for an extended period, resulting in lower future production of oil, gas and NGL; and
- reducing the carrying value of our properties, resulting in additional noncash write-downs.

Market prices and our realized prices have been volatile and are likely to continue to be volatile in the future due to numerous factors beyond our control. These factors include:

- the level of demand;
- domestic and global supplies of oil, NGL and gas;
- the price and quantity of imported and exported oil, NGL and gas;
- the actions of other oil exporting nations;
- weather conditions and changes in weather patterns;
- the availability, proximity and capacity of appropriate transportation facilities, gathering, processing and compression facilities, storage facilities and refining facilities;
- worldwide economic and political conditions, including political instability or armed conflict in oil and gas producing regions, competition for markets and political initiatives disfavoring fossil fuels;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the nature and extent of governmental regulation, including environmental regulation, regulation of derivatives transactions and hedging activities, tax laws and regulations and laws and regulations with respect to the import and export of oil, gas and related commodities;

- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others, and;
- the effect of worldwide energy conservation measures.

Our cash flows from operations, results of operations and the borrowing base under our credit facility depend to a great extent on the prevailing prices for oil and gas. Prolonged or substantial declines in oil and/or gas prices would materially and adversely affect our liquidity, the amount of cash flows we have available for our capital expenditures and other operating expenses, our ability to access the credit and capital markets and our results of operations.

The marketability of our production depends largely upon the availability, proximity and capacity of oil and gas gathering systems, pipelines, storage and processing facilities.

The marketability of our production depends in part upon processing, storage and transportation facilities, which are also known as midstream facilities, owned and operated by third parties. Transportation space on such gathering systems and pipelines is limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If adequate transportation and storage options are not available to us, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas. For example, our principal third party provider in the Bakken Field for these services has experienced significantly increased gathering system pressures which have resulted in capacity constraints. These constraints, in turn, have restricted our production and required us to flare gas, decreasing the volumes sold from our wells. Similarly, rapid production growth in the Permian Basin has strained the available midstream infrastructure there with adverse effects on our operations.

In addition to causing production curtailments and reducing the price we receive for the oil, gas and NGL we produce, given environmental impacts, including GHG production, regulatory agencies including the North Dakota Industrial Commission have adopted policies to reduce the volume of flared gas, the number of wells flaring and the duration of flaring. While these regulations have not had a material adverse effect on us to date, these current regulations relating to flaring gas or the adoption of additional regulations could cause us to shut-in production or curtail the drilling of new wells either of which could have a material adverse effect on us.

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We rely on third parties to continue to construct additional midstream facilities and related infrastructure to accommodate our growth, and the ability and willingness of those parties to do so is subject to a variety of risks.

For example:

- Decreases in commodity prices in recent years have resulted in reduced investment in midstream facilities by some third parties;
- Various interest groups have protested the construction of new pipelines, and particularly pipelines near water bodies, in various places throughout the country, and protests have at times physically interrupted pipeline construction activities;
- Some companies in our industry have sought to reject volume commitment agreements with midstream providers in bankruptcy proceedings, and the risk that such efforts will succeed, or that upstream energy company counterparties will otherwise be unable or unwilling to satisfy their volume commitments, may have the effect of reducing investment in midstream infrastructure; and

We have pursued a variety of strategies to alleviate some of the risks associated with the midstream services and facilities upon which we rely, including seeking alternative sources for processing and transporting gas that we produce. There can be no assurance that the strategies we pursue will be successful or adequate to meet our needs.

Any significant reduction in the borrowing base under our credit facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our credit facility or any other obligation if required as a result of a borrowing base redetermination

Availability under our credit facility is currently subject to a borrowing base of $200.0 million. The borrowing base is subject to scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. The lenders under our credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. A number of factors could reduce our borrowing base, including:

- lower commodity prices or production;
- a reduction in reserve estimates;

- inability to drill or unfavorable drilling results;
- increased operating and/or capital costs;
- the lenders’ inability to agree to an adequate borrowing base; or
- adverse changes in the lenders’ practices (including required regulatory changes) regarding estimation of reserves.

As of March 8, 2019, we had $180.0 million of borrowings outstanding and availability of $20.0 million under our credit facility. Any significant reduction in our borrowing base as a result of borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operations and cash flows from operations. Further, if the outstanding borrowings under our credit facility were to exceed the borrowing base as a result of redetermination, we would be required to repay the excess amount or pledge additional assets. We may not have sufficient funds to make such repayment and we do not have any substantial unpledged assets. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Lower oil and/or gas prices may also reduce the amount of oil and/or gas that we can produce economically.

Sustained substantial declines in oil and/or gas prices may render uneconomic a significant portion of our exploration, development and exploitation projects, which may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a prolonged or substantial decline in oil and/or gas prices such as we have experienced since mid-2014 has in the past caused, and would likely in the future cause, a material and adverse effect on our future business, financial condition, results of operations, liquidity and ability to finance capital expenditures. Additionally, if we experience significant sustained decreases in oil and gas prices such that the expected future cash flows from our oil and gas properties falls below the net book value of our properties, we may be required to write down the value of our oil and gas properties. Any such asset impairments could materially and adversely affect our results of operations and, in turn, the trading price of our common stock.

We may not be able to fund the capital expenditures that will be required for us to increase reserves and production.

We must make capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have financed our capital expenditures primarily with cash flows from operations, borrowings under credit facilities, sales of properties, monetizing derivative contracts and sales of debt and equity securities and we expect to continue to utilize these sources in the future to the extent available. We cannot assure you that we will have sufficient capital resources in the future to finance all of our planned capital expenditures.

Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flows from operations. Lower prices and/or lower production could also decrease revenues and cash flows from operations, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flows from operations does not increase as a result of capital expenditures, a greater percentage of our cash flows from operations will be required for debt service and operating expenses and our capital expenditures would, by necessity, be decreased.

If cash flows from operations or our borrowing base decrease, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under our credit facility is reduced, we would be required to reduce borrowings under our credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, we may be in default under the credit facility.

We have sold producing properties to provide us with liquidity and capital resources in the past and we may continue to do so in the future. After any such sale, we would expect to utilize the proceeds to reduce our indebtedness and/or to drill new wells on our remaining properties. If we cannot replace the production from the properties sold with production from our remaining properties, our cash flows from operations will likely decrease, which in turn, could decrease the amount of cash available for additional capital spending.

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Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our credit facility contains a number of significant covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- make any change in the principal nature of our business;
- permit a change of control; or
- consolidate, merge or transfer all or substantially all of our assets.

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In addition, our credit facility requires us to maintain compliance with specified financial covenants. Our ability to comply with these covenants may be adversely affected by events beyond our control, and we cannot assure you that we can maintain compliance with these covenants. These financial covenants could limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general or otherwise conduct necessary or desirable business activities. We are also required to use the proceeds from the termination of any derivative contracts to repay outstanding amounts under the credit facility and to use any amount of cash on hand and liquid investments in excess of $10.0 million to repay outstanding amounts under the credit facility.

A breach of any of these covenants could result in a default under our credit facility. For example, at December 31, 2018, we were not in compliance with the current ratio under our credit facility. While we received a waiver of this default, we cannot assure you that we will be able to obtain such waivers in the future. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms acceptable or favorable to us.

Lower oil and gas prices increase the risk of ceiling limitation write-downs.

We use the full cost method to account for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop our oil and gas properties. Under full cost accounting rules, the net capitalized cost of our oil and gas properties may not exceed a “ceiling limit” which is based upon the present value of estimated future net cash flows from our proved reserves, discounted at 10%. If the net capitalized costs of our oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a “ceiling limitation write-down.” This charge does not impact cash flows from operating activities, but it does reduce our stockholders’ equity and earnings. The risk that we will be required to write-down the carrying value of our oil and gas properties increases when oil and gas prices are low, which could be further impacted by the SEC’s oil and gas reporting disclosures, which require us to use an average price over the prior 12-month period, rather than the year-end price, when calculating the PV-10. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though oil and gas prices may have increased the ceiling applicable in the subsequent period.

During 2016, the net capitalized costs of our oil and gas properties exceeded the present value of estimated future cash flows from our proved reserves, resulting in recognition of impairments totaling $67.6 million. While we did not recognize any impairments in 2017 or 2018, if commodity prices decrease in the future, we would likely be required to record further write downs.

An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flows from operations.

Our oil and gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for our oil and gas are typically lower than the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, location to market, product quality, pipeline capacity and specifications, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Additionally, insufficient pipeline capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas. For example, production increases from competing Canadian and Rocky Mountain producers, combined with limited refining and pipeline capacity in the Rocky Mountain area, have gradually widened differentials in this area. In addition, we have a gas sales contract related to certain gas and NGL produced in the Rocky Mountain Region, which provides that if certain margins of gas and NGL prices are not met by the purchaser, we receive no sales proceeds.

During 2018, our differentials averaged ($7.39) per Bbl of oil and ($1.36) per Mcf of gas. Approximately 57% of our oil production during 2018 was from the Rocky Mountain region and approximately 37% from the Permian region. As our production from the Rocky Mountain and Permian regions continues to increase, we expect that the effect our price differentials on our revenues will also increase. Increases in the differential between the benchmark prices for oil and gas and the realized price we receive could significantly reduce our revenues and our cash flow from operations.

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Our derivative contracts could result in financial losses or could reduce our cash flows.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and gas, we enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 51% of the oil production from our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021.These arrangements may be inadequate to protect us from declines in oil and gas prices. Any new hedging arrangements will be priced at then-current market prices and may be significantly lower than the commodity swaps we currently have in place. The extent of our commodity price exposure will be related largely to the effectiveness and scope of our commodity price derivative contracts. For example, the prices utilized in our derivative contracts are currently NYMEX-based, which may differ significantly from the actual prices we receive for oil and gas which are based on the local markets where the oil and gas is produced. The prices that we receive for our oil and gas production are typically lower than the relevant benchmark prices that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential, a significant portion of which is based on the delivery location which is called the basis differential. As a result, our cash flows from operations could be affected if the basis differentials widen more than we anticipate. We have entered into basis swaps to mitigate some of the effects of differentials, however they do not alleviate all of the effects of such differentials. Our cash flows from operations could also be affected based upon the levels of our production. If production is higher than we estimate, we will have greater commodity price exposure than we intended. If production is lower than the nominal amount that is subject to our hedging arrangements, we may be forced to satisfy all or a portion of our hedging arrangements without the benefit of the cash flows from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows from operations.

If the prices at which we hedge our oil and gas production are less than current market prices, our cash flows from operations could be adversely affected.

When our derivative contract prices are higher than market prices, we will incur realized and unrealized gains on our derivative contracts and conversely, when our contract prices are lower than market prices, we will incur realized and unrealized losses. For the year ended December 31, 2018, we recognized a gain on our oil and gas derivative contracts of $8.1 million, consisting of a loss of $19.0 million on our settled contracts and a gain of $27.1 million on open contracts. The loss on settled contracts resulted in a decrease in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility.

We cannot assure you that the derivative contracts that we have entered into, or will enter into, will adequately protect us from financial loss in the future due to circumstances such as:

- highly volatile oil and gas prices;
- our production being less than expected; or
- a counterparty to one of our hedging transactions defaulting on its contractual obligations.

The counterparties to our derivative contracts may be unable to perform their obligations to us which could adversely affect our cash flows.

At times when market prices are lower than our derivative contract prices, we are entitled to cash payments from the counterparties to our derivative contracts. Any number of factors may adversely affect the ability of our counterparties to fulfill their contractual obligations to us. If one of our counterparties is unable or unwilling to make the required payments to us, it could adversely affect our cash flows from operations.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development and exploratory drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. For example, the Company's proved reserves as of December 31, 2018 include proved undeveloped reserves and proved developed reserves that are behind pipe of 29,448 MBbls of oil, 6,355 MBbls of NGL and 50,567 MMcf of gas. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. There can be no assurance that the Company will drill these locations or that the Company will be able to produce oil or gas reserves from these locations or any other potential drilling locations. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately result in the realization of proved reserves or meet the Company's expectations for success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

A significant portion of the Company's total estimated proved reserves at December 31, 2018 were undeveloped, and those proved reserves may not ultimately be developed.

At December 31, 2018, approximately 63% of the Company's total estimated proved reserves on a Boe basis were undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling. The Company's reserve data assumes that the Company can and will make these expenditures and conduct these operations successfully, which assumptions may not prove correct. If the Company chooses not to spend the capital to develop these proved undeveloped reserves, or if the Company is not otherwise able to successfully develop these proved undeveloped reserves, the Company will be required to write-off these reserves. In addition, under the SEC's rules, because proved undeveloped reserves may be booked only if they relate to wells planned to be drilled within five years of the date of booking, the Company may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. As with all oil and gas leases, the Company's leases require the Company to drill wells that are commercially productive and to maintain the production in paying quantities, and if the Company is unsuccessful in drilling such wells and maintaining such production, the Company could lose its rights under such leases. The Company's future production levels and, therefore, its future cash flows and income from operations are highly dependent on successfully developing its proved undeveloped leasehold acreage.

We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced. Unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, we cannot assure you that our exploration and development activities will result in increases in our proved reserves. Based on the reserve information set forth in our reserve report as of December 31, 2018, our average annual estimated decline rate for our net proved developed producing reserves is 35%; 19%; 14%; 11% and 9% in 2019, 2020, 2021, 2022 and 2023, respectively, 11% in the following five years, and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially higher. We have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. As our proved reserves and consequently our production decline, our cash flow from operations, and the amount that we are able to borrow under our credit facility could also decline. In addition, approximately 63% of our total estimated proved reserves on a Boe basis at December 31, 2018 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Even if we are successful in our development efforts, it could take several years for a significant portion of these undeveloped reserves to generate positive cash flow.

We may not find any commercially productive oil and gas reservoirs.

Drilling involves numerous risks, including the risk that the new wells we drill will be unproductive or that we will not recover all or any portion of our capital investment. Drilling for oil and gas may be unprofitable. Wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. The inherent risk of not finding commercially productive reservoirs is compounded by the fact that 63% of our total estimated proved reserves on a Boe basis as of December 31, 2018 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling and completion operations. If the volume of oil and gas we produce decreases, our cash flows from operations may decrease.

The results of our drilling in unconventional formations, principally in emerging plays with limited drilling and production history using long laterals and modern completion techniques, are subject to more uncertainties than our drilling program in the more established plays and may not meet our expectations for reserves or production.

We drill wells in unconventional formations in several emerging plays. Part of our drilling strategy to maximize recoveries from these formations involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have proven to be successful in other basins. Risks that we face include landing our well bore in the desired drilling zone, staying in the desired drilling zone, running casing the entire length of the well bore and being able to run tools and recover equipment the entire length of the well bore during completion. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date, as well as the industry's drilling and production history in these formations, is relatively limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established. In addition, based on reported decline rates in these emerging plays as well as the industry's experience in these formations, we estimate that the average monthly rates of production may decline as much as 95% during the first twelve months of production. Actual decline rates may differ significantly. Accordingly, the results of our drilling in these unconventional formations are more uncertain than drilling results in other more established plays with longer reserve and production histories.

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We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- prevailing and anticipated prices for oil and gas;
- the availability and costs of drilling and service equipment and crews;
- economic and industry conditions at the time of drilling;
- the availability of sufficient capital resources;
- the results of our exploitation efforts;
- the acquisition, review and interpretation of seismic data;
- our ability to obtain permits for and to access drilling locations;
- continuous drilling obligations; and

- lease expirations.

Although we have identified or budgeted for numerous drilling locations, we may not be able to drill those locations within our expected time frame or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties. For example, we have in the past, and may be required in the future, to delay drilling or completing wells in order to protect them from fracture stimulation of other wells in the same area.

We cannot control the activities on the properties we do not operate and are unable to ensure their proper operation and profitability.

We currently do not operate all of the properties in which we have an interest. Non-operated properties represented approximately 4% of our estimated net proved reserves on a Boe basis. at December 31, 2018. As a result, we have limited ability to exercise influence over and control the risks associated with operation of these properties. The failure of an operator to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including:

- the operator could refuse to initiate exploitation or development projects and if we proceed with any of those projects, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploitation or development projects on a different schedule than we would prefer;
- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects and thus, not participate in the associated revenue stream; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploitation and development activities.

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Seasonal weather conditions and other factors could adversely affect our ability to conduct drilling activities.

Our operations could be adversely affected by weather conditions and wildlife restrictions on federal leases. In the Williston Basin, drilling and other oil and gas activities cannot be conducted as efficiently during the winter and spring months. Winter and severe weather conditions limit and may temporarily halt the ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our oil and gas operations and materially increase our operating and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

The lack of availability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploitation and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there has been a shortage of drilling rigs, equipment, supplies, oil field services or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. During times and in areas of increased activity, the demand for oilfield services will also likely rise, and the costs of these services will likely increase, while the quality of these services may suffer. If the lack of availability or high cost of drilling rigs, equipment, supplies, oil field services or qualified personnel were particularly severe in any of our areas of operation, we could be materially and adversely affected. Delays could also have an adverse effect on our results of operations, including the timing of the initiation of production from new wells.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors that are beyond our control.

Our drilling operations are subject to a number of risks, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- adverse weather conditions;

- title problems;
- delays due to protection from fracture stimulations of nearby wells,
- unusual or unexpected geological formations;
- fires, blowouts and explosions; and
- uncontrollable pressures or flows of oil or gas or well fluids.

Any of these events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension of operations, and attorney’s fees and other expenses incurred in the prosecution or defense of litigation.

We do not insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and gas operations.

We do not insure against all risks. Our oil and gas exploitation and production activities are subject to hazards and risks associated with drilling for, producing and transporting oil and gas, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, underground migration and surface spills or mishandling of chemical additives;
- abnormally pressured formations;

- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- leaks of gas, oil, condensate, NGL and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, or in the gathering and transportation of hydrocarbons, malfunctions of pipelines, measurement equipment or processing or other facilities in the Company's operations or at delivery points to third parties;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

We might elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations.

Hydraulic fracturing, the process used for extracting oil and gas from shale and other formations, could be the subject of further regulation that could impact the timing and cost of development.

Hydraulic fracturing is the primary completion method used to extract reserves located in many of the unconventional oil and gas plays. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure, usually down tubing or casing that is cemented in the wellbore, into hydrocarbon-bearing formations at depth to stimulate oil and gas production. We use this completion technique on substantially all of our wells. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal and state levels, exploration, exploitation and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Some states in which we operate, including Texas, have implemented disclosure requirements related to chemicals used in hydraulic fracturing, and while the BLM has rescinded its rules governing hydraulic fracturing on federal and tribal lands (which action itself is subject to pending litigation), we anticipate further regulation of hydraulic fracturing and related activities by states and local governments. Individually or collectively, such existing and new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business, financial condition and results of operations.

Hydraulic fracturing is typically regulated by state oil and gas commissions; however, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Underground Injection Control Program established under the Safe Drinking Water Act, or SDWA, and published permitting guidance and an interpretive memorandum addressing the performance of such activities. In addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development or production activities.

Certain states in which we operate, including Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosures, and/or well-construction requirements on hydraulic-fracturing operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact water available for hydraulic fracturing. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, in the event state or local restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

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See “Item 1. Business – Environmental Matters – Hydraulic Fracturing” above for additional discussion related to environmental risks associated with our hydraulic fracturing activities.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows from operations.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Over the past few years, extreme drought conditions persisted in West and South Texas. Although conditions have improved, we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local resources, we may be unable to economically produce oil and gas, which could have an adverse effect on our financial condition, results of operations and cash flows from operations.

Studies noting a connection between increased seismic activity and the injection of wastewater from oil and gas operations could result in new laws or regulations which would increase our cost of operations.

Some studies have noted an increase in localized frequency of seismic activity associated with underground injection wastewater from oil and gas operations. If the results of these studies are confirmed, new legislative and regulatory initiatives could require additional monitoring, restrict the injection of produced water in certain disposal wells or modify or curtail hydraulic fracturing operations. These actions could lead to operational delays, increased compliance costs or otherwise adversely impact our operations.

We face various risks associated with the trend toward increased anti-development activity.

As new technologies have been applied to our industry, we have seen significant growth in oil and gas supply in recent years, particularly in the U.S. With this expansion of oil and gas development activity, opposition toward oil and gas drilling and development activity has been growing both in the U.S. and globally. Companies in the oil and gas industry, such as us, can be the target of opposition to development from certain stakeholder groups. These anti-development efforts could be focused on:

- limiting oil and gas development;

- reducing access to federal and state owned lands;
- delaying or canceling certain projects such as offshore drilling, shale development, and pipeline construction;
- limiting or banning the use of hydraulic fracturing;
- denying air-quality permits for drilling; and
- advocating for increased regulations on shale drilling and hydraulic fracturing.

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- reduce access to sand, or other proppants, required for hydraulic fracturing;

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- limited access or damage to or destruction of our property;
- legal challenges or lawsuits;
- increased regulation of our business;
- damaging publicity and reputational harm;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities could be substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations. In addition, the use of social media channels can be used to cause rapid, widespread reputational harm.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act establishes federal oversight and regulation of over-the-counter, or OTC, derivatives and requires the Commodity Futures Trading Commission, or CFTC, and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, on November 5, 2013 (as modified and re-proposed on December 30, 2016), the CFTC approved a proposed rule imposing position limits for certain futures and option contracts in various commodities (including gas) and for swaps that are their economic equivalents. Certain specified types of hedging transactions are proposed to be exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, on December 16, 2016, the CFTC issued a proposed rule regarding the capital that a swap dealer, or major swap participant, is required to post with respect to its swap business, but has not yet issued a final rule. On January 6, 2016, the CFTC issued a final rule on margin requirements for uncleared swap transactions, which includes an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions. In addition, on July 19, 2012, the CFTC issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations and requirements could increase the costs to us of entering into, and lessen the availability to us, derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business.

It is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements. Moreover, our ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks may affect whether we are required to comply with margin and certain clearing and trade-execution requirements in connection with our derivative activities. If we do not qualify for the commercial end-user exception, we may be required to post margin or clear certain transactions, which could reduce our liquidity and cash available for capital expenditures and our ability to hedge may be impacted. When a final rule on capital requirements is issued, the Dodd-Frank Act may require our current swap counterparties to post additional capital as a result of entering into uncleared derivatives with us, which could increase the costs to us of entering into, and lessen the availability of us to, derivative contracts. The Dodd-Frank Act may also require our current counterparties to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the derivatives markets thereby reducing the ability of commercial end-users to have access to derivative contracts to hedge or mitigate their exposure to volatility in oil, gas, and NGL prices. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated derivative contracts, and reduce the availability of derivatives to protect us against commercial risks we encounter.

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In addition, federal banking regulators have adopted new capital requirements for certain regulated financial institutions in connection with the Basel III Accord. The Federal Reserve Board also issued proposed regulations on September 30, 2016, proposing to impose higher risk-weighted capital requirements on financial institutions active in physical commodities, such as oil and gas. If and when these proposed regulations are fully implemented, financial institutions subject to these higher capital requirements may require that we provide cash or other collateral with respect to our obligations under the financial derivatives and other contracts we may enter into with such financial institutions in order to reduce the amount of capital such financial institutions may have to maintain. Alternatively, financial institutions subject to these capital requirements may price transactions so that we will have to pay a premium to enter into derivatives and other physical commodity transactions in an amount that will compensate the financial institutions for the additional capital costs relating to such derivatives and physical commodity transactions. Rules implementing the Basel III Accord and higher risk-weighted capital requirements could materially reduce our liquidity and increase the cost of derivative contracts and other physical commodity contracts (including through requirements to post collateral, which could adversely affect our available capital for other commercial operations purposes). In addition, certain foreign jurisdictions may adopt or implement laws and regulations relating to margin and central clearing requirements, which in each case may affect our counterparties and the derivatives markets generally.

If we reduce our use of derivative contracts as a result of any of the foregoing regulations or requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, gas, and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, gas, and NGL. 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 our financial position, results of operations, or cash flows from operations.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carry forwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2018, we had pre 2018 net operating loss carryforwards or NOLs, for federal income tax purposes of $245.2 million and a 2018 NOLs of $46.8 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period.

As a result of the Tax Cuts and Jobs Act of 2017, NOLs arising before January 1, 2018, and NOLs arising after January 1, 2018, are subject to different rules. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018, can generally be carried forward indefinitely and can offset up to 80% of future taxable income. Our ability to use our NOLs during this period will be dependent on our ability to generate taxable income, and the NOLs could expire before we generate sufficient taxable income.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. In addition, computer technology controls nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced significant cyber attacks, we may suffer such attacks in the future. Further, as cyber attacks 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 vulnerability to cyber attacks.

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We rely on independent experts and technical or operational service providers over whom we may have limited control.

We use independent contractors to provide us with certain technical assistance and services. We rely upon the owners and operators of rigs and drilling equipment, and upon providers of field services, to drill and develop our prospects to production. We also rely upon the services of other third parties to explore and/or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. Our limited control over the activities and business practices of these service providers, any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially adversely affect our business, results of operations and financial condition.

We depend on our President, CEO and Chairman of the Board and the loss of his services could have an adverse effect on our operations.

We depend to a large extent on Robert L.G. Watson, our President and Chief Executive Officer, for our management, business and financial contacts. Mr. Watson may terminate his employment agreement with us at any time on 30 days' notice, but, if he terminates without good reason, he would not be entitled to the severance benefits provided under the terms of that agreement. Mr. Watson is not precluded from working for, with or on behalf of a competitor upon termination of his employment with us. If Mr. Watson were no longer able or willing to act as President, Chief Executive Officer and Chairman of the Board, the loss of his services could have an adverse effect on our operations.

Risks Related to Our Industry

Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows from operations, profitability and growth.

Our revenue, cash flows from operations, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Prices also affect the amount of cash flows available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also make it uneconomical for us to increase or even continue current production levels of oil and gas.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and gas, market uncertainty and a variety of other factors beyond our control, including:

- changes in foreign and domestic supply and demand for oil and gas;
- political stability and economic conditions in oil producing countries, particularly in the Middle East;
- weather conditions;
- price and level of foreign imports;
- terrorist activity;
- availability of pipeline and other secondary capacity;
- general economic conditions;
- domestic and foreign governmental regulation; and
- the price and availability of alternative fuel sources.

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Estimates of proved reserves and future net revenue are inherently imprecise.

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

The estimates of our reserves as of December 31, 2018 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the present value of our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2018. The average realized sales prices used for purposes of such estimates were $59.65 per Bbl of oil and $1.76 per Mcf of gas. The December 31, 2018 estimates also assume that we will make future capital expenditures of approximately $547.2 million in the aggregate primarily from 2019 through 2023, which are necessary to develop and realize the value of proved reserves on our properties. We cannot assure you that we will have sufficient capital in the future to make these capital expenditures. In addition, approximately 63% of our total estimated proved reserves on a Boe basis as of December 31, 2018 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of our reserves set forth or incorporated by reference in this report.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

As required by SEC regulations, we based the estimated discounted future net cash flows from our proved reserves as of December 31, 2018 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2018 and costs in effect on December 31, 2018, the date of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

- supply of and demand for our oil and gas;
- actual prices we receive for our oil and gas;

- our actual operating costs;

- the amount and timing of our capital expenditures;

- the amount and timing of our actual production; and

- changes in governmental regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows, which is required by the SEC, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our operations are subject to the numerous risks of oil and gas drilling and production activities.

Our oil and gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil and salt water spills, gas leaks, ruptures, discharges of toxic gases, underground migration and surface spills or mishandling of any toxic fracture fluids, including chemical additives. In addition, title problems, weather conditions and mechanical difficulties or shortages or delays in delivery of drilling rigs and other equipment could negatively affect our operations. If any of these or other similar industry operating risks occur, we could have substantial losses. Substantial losses also may result from injury or loss of life, severe damage to or destruction of property, clean-up responsibilities, environmental damage, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We operate in a highly competitive industry which may adversely affect our operations.

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations, we cannot assure you that such resources will be available to us in the future.

Our oil and gas operations are subject to various U.S. federal, state and local regulations that materially affect our operations.

In the oil and gas industry, matters regulated include permits for drilling and completion operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties, the disposal of wastes and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and gas, these agencies have at times restricted the rates of flow from oil and gas wells below actual production capacity. U.S. federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas by-products and other substances and materials produced or used in connection with oil and gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Recently enacted federal legislation will affect our tax position concerning tax deductions currently available with respect to oil and gas drilling may adversely affect our net earnings.

In December 2017, Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act, or TCJA. The law made significant changes to U.S. federal income tax laws, including reducing the corporate income tax rate from 35 percent to 21 percent, repealing the corporate alternative minimum tax, or AMT, partially limiting the deductibility of interest expense and NOLs, eliminating the deduction for certain U.S. production activities and allowing the immediate deduction of certain new investments in lieu of depreciation expense over time. Many aspects of the TCJA are unclear and may not be clarified for some time.

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and gas exploration and production activities in certain U.S. federal income tax incentives and deductions currently available to such companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective and whether such changes may apply retroactively. Although we are unable to predict whether any of these or other proposals will ultimately be enacted, the passage of any legislation as a result of these proposals or any other similar changes to U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available to us, and any such change could negatively affect our financial condition and results of operations.

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Climate change and regulations related to GHGs could have an adverse effect on our operations and on the demand for oil and gas.

Scientific studies have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. Domestically, the Fourth National Climate Assessment report, released in November 2018, noted that climate change is mostly driven by GHG emissions and that climate change is accelerating. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered GHGs. We expect continuing debate, especially in the political arena, over how to address climate change and what policies and regulations are necessary to address the issue. In response to various scientific studies, governments have begun adopting domestic and international climate change regulations that require reporting and reduction of emissions of GHGs. It is possible that international efforts spear-headed by the United Nations and subsequent domestic and international regulations will have adverse effects on the market for oil, gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, oil, gas and other fossil fuel products. In the United States, at the state level and local level, several states and localities, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of GHGs. At the federal level, various climate change legislative measures have been considered by the U.S. Congress, but it is not possible at this time to predict when, or if, Congress will act on climate change legislation, although any major initiatives in this area are unlikely to become law in the near future due to opposition in Congress. We are unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect our operations, financial condition and results of operations.

Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and gas that we produce and, as a result, our financial condition and results of operations could be adversely affected.

In addition, local weather effects associated with climate change, including more severe rainfall events, more intense storms, flooding, or droughts could adversely affect our facilities or the scheduling of deliveries or the cost of supplies needed to run our business.

EPA's ground-level ozone standards may result in more stringent regulation of air emissions from, and adverse economic impacts on, our operations.

Effective December 2015, the EPA adopted a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards designed to provide protection of public health and welfare, respectively. EPA has now issued new area designations with respect to ground-level ozone, and in November 2018 EPA issued final requirements for implementation that apply to state and local agencies. Areas of the country that have been reclassified so that they are no longer in attainment with the 2015 standard will be more costly and difficult for operators to construct new or modified sources of air pollution, including those associated with our operations. Moreover, such reclassified areas more stringent regulations may require among other things, installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

Proposed legislation and regulation under consideration regarding rail transportation could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

We presently sell all of our oil production at the lease, either by truck or pipeline, where custody transfers to the purchaser, accordingly it is unknown to us how much of the oil production is ultimately shipped by rail. In response to recent train derailments occurring in the United States, U.S. regulators are implementing or considering new rules to address the safety risks of transporting oil by rail. On January 23, 2014, the NTSB issued a series of recommendations to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) developing an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) auditing shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the DOT issued an emergency order requiring all persons, prior to offering oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of oil be handled as a Packing Group I or II hazardous material. The introduction of these or other regulations that result in new requirements addressing the type, design, specifications or construction of rail cars used to transport oil could result in severe transportation capacity constraints during the period in which new rail cars are retrofitted or constructed to meet new specifications.

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We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or rail transportation of oil could increase our costs of doing business and limit our ability to transport and sell our oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows from operations.

Risks Related to Our Common Stock

Future issuance of additional shares of common stock could cause dilution of ownership interests and adversely affect our stock price.

We are currently authorized to issue 400,000,000 shares of common stock with such rights as determined by our board of directors. In the future, we may increase our authorized shares of common stock or issue previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. The potential issuance of any such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

We will not pay dividends on our common stock for the foreseeable future.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. In addition, our credit facility prohibits us from paying dividends and making other cash distributions.

Shares eligible for future sale may depress our stock price.

At December 31, 2018, we had 166,713,784 shares of common stock outstanding of which 4,179,187 shares were held by affiliates and, in addition, 7,549,448 shares of common stock were subject to outstanding options granted under stock option plans (of which 6,478,948 shares were vested at December 31, 2018).

All of the shares of common stock held by affiliates are restricted or are control securities under Rule 144 promulgated under the Securities Act. The shares of common stock issuable upon exercise of stock options have been registered under the Securities Act. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of our common stock and could impair our ability to raise additional capital through the sale of equity securities.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Our common stock is traded on The NASDAQ Stock Market. The market price of our common stock has been volatile and could fluctuate substantially based on a variety of factors, including the following:

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the oil and gas industry;
- sales of common stock or other actions by our stockholders;
- additions or departures of key management personnel;
- commencement of or involvement in litigation;
- speculation in the press or investment community regarding our business;
- an inability to maintain the listing of our common stock on a national securities exchange;
- market conditions; and
- analysts' estimates and other events in the oil and gas industry.

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We may issue shares of preferred stock with greater rights than our common stock.

Subject to the rules of The NASDAQ Stock Market, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock.

Anti-takeover provisions could make a third party acquisition of us difficult.

Our articles of incorporation and bylaws provide for a classified board of directors, with each member serving a three-year term, and eliminate the ability of stockholders to call special meetings or take action by written consent. Each of the provisions in our articles of incorporation and bylaws could make it more difficult for a third party to acquire us without the approval of our board. In addition, the Nevada corporate statute also contains certain provisions that could make an acquisition by a third party more difficult.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Exploratory and Developmental Acreage

Our principal oil and gas properties consist of producing and non-producing oil and gas leases, including reserves of oil and gas in place. The following table sets forth our developed and undeveloped acreage and fee mineral acreage as of December 31, 2018.

	Developed Acreage	Undeveloped Acreage	Fee Mineral Acreage (1)

	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres (2)
Permian/Delaware Basin	15,639	11,566	13,986	9,415	12,648	2,391	23,372
Rocky Mountain	27,376	14,500	12,343	5,769	3,078	346	20,615
South Texas	7,982	7,502	4,745	4,688	2,603	739	12,929
Total	50,997	33,568	31,074	19,872	18,329	3,476	56,916

(1) Fee mineral acreage represents fee simple absolute ownership of the mineral estate or fraction thereof.
(2) Includes 640 net acres in the Permian Basin region that are included in both developed and fee mineral acres.

The following table sets forth Abraxas' net undeveloped acreage subject to expiration by year:

	2019	2020	2021	2022	2023
Permian/Delaware Basin	176	315	-	-	-
Rocky Mountain	3	426	-	-	-
South Texas	1,798	2,020	-	-	-
Total	1,977	2,761	-	-	-

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2018:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Permian/Delaware Basin	63.0	52.4	52.0	33.3
Rocky Mountain	228.0	67.6	311.0	6.8
South Texas	15.0	15.0	9.0	8.3
	306.0	135.0	372.0	48.4

Reserves Information

The estimation and disclosure requirements we employ conform to the definition of proved reserves with the Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. This accounting standard requires that the average first-day-of-the-month price during the 12-month period preceding the end of the year be used when estimating reserve quantities and permits the use of reliable technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes.

The Company’s proved oil and gas reserves have been estimated by an independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2016, and 2017 and LaRoche Petroleum Consultants as of December 31, 2018, assisted by the engineering and operations departments of the Company. For the year ended December 31, 2018, LaRoche Petroleum Consultants, Ltd., of Dallas, Texas estimated reserves for our properties comprising approximately 99% of the PV-10 of our proved oil and gas reserves. Proved reserves for the remaining 1% of our properties were estimated by Abraxas personnel because we determined that it was not practical for LaRoche Petroleum Consultants, Ltd. to prepare reserve estimates for these properties as they are located in a widely dispersed geographic area and have relatively low value. LaRoche Petroleum Consultants, Ltd's reserve report as of December 31, 2018 included a total of 316 properties and our internal report included 201 properties.

The technical personnel responsible for preparing the reserve estimates at LaRoche Petroleum Consultants, Ltd. 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. LaRoche Petroleum Consultants, Ltd. is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists. They do not own an interest in any of our properties and are not employed on a contingent fee basis. All reports by LaRoche Petroleum Consultants, Ltd. were developed utilizing their own geological and engineering data, supplemented by data provided by Abraxas. The report of LaRoche Petroleum Consultants, Ltd. dated February 12, 2019, which contains further discussions of the reserve estimates and evaluations prepared by LaRoche Petroleum Consultants, Ltd. as well as the qualifications of LaRoche Petroleum Consultants, Ltd.’s technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of reserves at December 31, 2018 were based on studies performed by the engineering department of Abraxas which is directly responsible for Abraxas’ reserve evaluation process. The Vice President of Engineering manages this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and is a Registered Professional Engineer in the State of Texas; he has 40 years of experience in reserve evaluations. The operations department of Abraxas assisted in the process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including oil and gas prices, production costs, future capital expenditures and Abraxas’ net ownership percentages, were obtained from other departments within Abraxas.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and Financial Accounting Standards Board, or FASB, guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations or de-escalations except by contractual arrangements. For the year ended December 31, 2018, commodity prices over the prior 12-month period and year end costs were used in estimating future net cash flows.

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2018. All of our reserves are located in the United States.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2018

Reserve Category	**Oil (MBbls)**	**NGL (MBbls)**	**Gas (MMcf)**	**Oil equivalents (MBoe)**
Proved				
Developed	13,586	3,804	43,271	24,602
Undeveloped	28,651	6,230	46,473	42,626
Total Proved	42,237	10,034	89,744	67,228

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2016, 2017, and 2018, and changes in proved reserves during the last three years are presented in the *Supplemental Oil and Gas Disclosures* under Item 8 of this report. Also presented in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves.

We have not filed information with a federal authority or agency with respect to our estimated total proved reserves at December 31, 2018. We report gross proved reserves of operated properties in the United States to the U.S. Department of Energy on an annual basis; these reported reserves are derived from the same data used to estimate and report proved reserves in this report.

The process of estimating oil and gas reserves is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves set forth or incorporated by reference in this report. We may also adjust estimates of reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. In particular, estimates of oil and gas reserves, future net revenue from reserves and the PV-10 thereof for the oil and gas properties described in this report are based on the assumption that future oil and gas prices remain the same as oil and gas prices utilized in the December 31, 2018 report. The average realized sales prices used for purposes of such estimates were $59.65 per Bbl of oil and $1.76 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $547.2 million in the aggregate primarily in the years 2019 through 2023, which are necessary to develop and realize the value of proved reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

You should not assume that the present value of future net revenues referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are calculated using the average first-day-of-the-month price over the prior 12-month period. Costs used in the estimated discounted future net cash flows are costs as of the end of the period. Because we use the full cost method to account for our oil and gas operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. This is known as a “ceiling limitation write-down.” This charge does not impact cash flows from operating activities but does reduce our stockholders’ equity and reported earnings. We have experienced ceiling limitation write-downs in the past and we cannot assure you that we will not experience additional ceiling limitation write-downs in the future. As of December 31, 2018 and 2017, the Company’s net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. During 2016, we recorded a proved property impairment of $67.6 million. If commodity prices decrease, we could be required to further write down the carrying value of our reserves during 2019 which would also reduce our net income.

For more information regarding the full cost method of accounting, you should read the information under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies."

Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. Our effective interest rate on borrowings at various times and the risks associated with us or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

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Proved Undeveloped Reserves

Changes in PUDs. Significant changes to PUDs that occurred during 2018 are summarized in the table below. Revisions of prior estimates reflect the addition of new PUDs associated with current development plans, revisions to prior PUDs, revisions to infill drilling development plans, as well as the transfer of PUDs to unproved reserve categories due to changes in development plans during the year. Our year-end development plans are consistent with SEC guidelines for PUDs development within five years unless specific circumstances warrant a longer development time horizon. There were no PUDs as of December 31, 2016, 2017 and 2018 as set forth in this report that are not planned to be developed within five years.

The following is a summary of the changes to the Company's proved undeveloped reserves that occurred during 2018:

	MBoe
PUDs at December 31, 2017	43,631
Revisions of prior estimates	3,040
Extensions, discoveries , and other additions	13,303
Conversion to developed	(5,811)
Conversion to probable	(8,078)
Sales	(3,459)
PUDs at December 31, 2018	42,626

We spent approximately $56.3 million converting proved undeveloped reserves to proved developed reserves in 2018. The following is a summary of the changes to the Company’s proved undeveloped reserves that occurred during 2018.

Revisions of prior estimates:

An increase of 3,040 MBoe of net reserves was attributed to increased economic life calculations at the higher commodity pricing experienced during 2018.

Extensions, discoveries and other additions:

The Company added sixteen new proved undeveloped Wolfcamp A locations, and three 3rd Bone Spring locations in Ward County, Texas, accounting for 8,530 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing wells or those operated by others. The Company added two new proved undeveloped Middle Bakken locations, and one Three Forks location in McKenzie County, North Dakota, accounting for 1,692 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing well or those operated by others. The Company purchased two proved undeveloped non-operated locations in Ward County, Texas during 2018 accounting for 411 MBoe of net reserves. The Company also converted five probable undeveloped Wolfcamp A locations, and one Wolfcamp B locations in Ward County, Texas, to proved undeveloped reserves during 2018 accounting for 2,670 MBoe of net reserves.

Conversion to developed:

The Company converted four proved undeveloped Wolfcamp A locations in Ward County, Texas, to proved developed reserves during 2018 accounting for 917 MBoe of net reserves. The Company converted thirteen proved undeveloped Bakken and Three Forks locations in McKenzie County, North Dakota, to proved developed reserves during 2018 accounting for 4,452 MBoe of net reserves. There was also one proved undeveloped Bakken location in McKenzie County, North Dakota, converted to proved non-producing reserves during 2018 accounting for 415 MBoe of net reserves. Also, there were nine non-operated proved undeveloped Bakken and Three Forks locations in McKenzie County, North Dakota, converted to proved developed producing reserves during 2018 accounting for 24 MBoe of net reserves. There was also one non-operated proved undeveloped Bakken location in McKenzie County, North Dakota, converted to proved non-producing reserves during 2018 accounting for 3 MBoe of net reserves.

Conversion to probable:

The Company converted twenty-two proved undeveloped Three Forks 2nd Bench locations in McKenzie County, North Dakota, to probable undeveloped reserves during 2018 accounting for 6,885 MBoe of net reserves. There was also one proved undeveloped Rockies location in Billings County, North Dakota, converted to probable undeveloped reserves during 2018 accounting for 136 MBoe of net reserves. Also, there were twelve non-operated proved undeveloped Bakken and Three Forks locations in McKenzie County, North Dakota, converted to probable undeveloped reserves during 2018 accounting for 1,052 MBoe of net reserves. There was one non-operated proved undeveloped Rockies location in Billings County, North Dakota, converted to probable undeveloped reserves during 2018 accounting for 5 MBoe of net reserves. All of these locations are no longer included in the Company’s five-year development schedule.

Sold:

The Company sold two properties in Ward County, Texas that included 3,459 MBoe of net proved undeveloped Montoya reserves.

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Reconciliation of Standardized Measure to PV-10

PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 at December 31, 2017 and 2018:

	December 31,	
	2017	**2018**
	(In thousands)	
Standardized measure of discounted future net cash flows	$405,741	$651,884
Present value of future income taxes discounted at 10%	21,700	37,413
PV-10	$427,441	$689,297

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Oil and Gas Production, Sales Prices and Production Costs

The following table presents our net oil, gas and NGL production, the average sales price per Bbl of oil and NGL and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three years ended December 31, by our major operating regions:

	2016	2017	2018
Oil Production (Bbl)			
Permian	85,966	358,158	843,235
Rocky Mountain	1,102,852	1,094,170	1,343,666
South Texas	183,543	121,195	120,987
Total	1,372,361	1,573,523	2,307,888
Gas Production (Mcf)			
Permian	742,280	1,476,021	1,948,092
Rocky Mountain	1,756,462	1,910,876	2,122,215
South Texas	660,978	502,276	516,493
Total	3,159,720	3,889,173	4,586,800
NGL Production (Bbl)			
Permian	52,294	106,521	159,756
Rocky Mountain	300,669	364,202	342,482
South Texas	10,376	5,221	5,855
Total	363,339	475,944	508,093
Total Production (Boe) (1)	2,262,320	2,697,664	3,580,450
Average sales price per Bbl of oil (2)			
Permian	$41.30	$49.48	$55.95
Rocky Mountain	$36.31	$45.40	$57.80
South Texas	$40.13	$51.09	$66.66
Composite	$37.14	$46.76	$57.59
Average sales price per Mcf of gas			
Permian	$2.25	$2.05	$1.38
Rocky Mountain	$0.61	$1.41	$1.84
South Texas	$1.87	$2.34	$2.41
Composite	$1.26	$1.77	$1.71
Average sales price per Bbl of NGL			
Permian	$12.70	$17.28	$18.05
Rocky Mountain	$2.64	$10.36	$15.34
South Texas	$8.94	$17.78	$23.15
Composite	$4.27	$11.99	$16.28
Average sales price per Boe (2)	$24.97	$31.95	$41.62
Average cost of production per Boe produced (3)			
Permian	$13.97	$5.87	$6.59
Rocky Mountain	$3.68	$4.20	$6.13

South Texas	$16.54	$15.46	$15.79
Composite	$6.60	$5.51	$6.87

(1) Oil and gas were combined by converting gas to Boe on the basis of 6 Mcf of gas to 1 Bbl of oil.
(2) Before the impact of hedging activities.
(3) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

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Within the above major operating regions, the Rocky Mountain and the Permian/Delaware regions represented more than 15% of our proved reserves as of December 31, 2018. The following is a summary, by product sold, for each primary field in these regions, which represented 15% or more of our total proved reserves as of December 31, 2018, for the three years ended December 31:

	2016	**2017**	**2018**
Rocky Mountain Region			
Oil production (Bbls)			
Bakken/Three Forks	997,641	990,959	1,213,782
Gas Production (Mcf)			
Bakken/Three Forks	1,437,965	1,674,870	1,932,330
NGL production (Bbls)			
Bakken/Three Forks	286,232	357,850	341,191
Average sales price per Bbl of oil (1)			
Bakken/Three Forks	$36.38	$45.38	$57.77
Average sales price of per Mcf of gas			
Bakken/Three Forks	$0.40	$1.30	$1.76
Average sales price per Bbl of NGL			
Bakken/Three Forks	$2.00	$10.12	$15.36
Average cost of production per Boe produced (2)	$2.40	$3.15	$4.88
Permian Region			
Oil production (Bbls)	21,976	298,287	756,643
Wolfcamp			
Gas Production (Mcf)	13,002	238,711	640,273
Wolfcamp			
NGL production (Bbls)	2,918	44,159	100,141
Wolfcamp			
Average sales price per Bbl of oil (1)	$49.75	$49.91	$55.79
Wolfcamp			
Average sales price of per Mcf of gas	$3.57	$2.04	$1.31
Wolfcamp			
Average sales price per Bbl of NGL	$19.32	$18.16	$18.34
Wolfcamp			
Average cost of production per Boe produced (2)	$2.47	$1.58	$5.34

(1) Before the impact of hedging activities.
(2) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

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Drilling Activities

The following table sets forth our gross and net interests in exploratory and development wells drilled during the three years ended December 31:

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Permian/Delaware	1.0	1.0	-	-	-	-
Rocky Mountain	-	-	-	-	-	-
South Texas	1.0	1.0	1.0	1.0	-	-
Total	2.0	2.0	1.0	1.0	-	-
Development						
Productive						
Permian/Delaware	-	-	7.0	6.5	11.0	7.4
Rocky Mountain	6.0	4.7	14.0	5.1	36.0	6.4
South Texas	-	-	-	-	-	-
Total	6.0	4.7	21.0	11.6	47.0	13.8

In addition to the above drilling activity, as of December 31, 2018 we had 8.00 gross (4.2 net) operated wells and 2.0 gross (0.6 net) non-operated wells that were drilled and uncompleted that are not represented in the above table.

Present Activities

Williston Basin, North Dakota

Western North Dakota has experienced one of the coldest winters on record. Abraxas has experienced several days when all surface work was shut down due to temperatures and wind chill that put personnel safety and equipment reliability in jeopardy. Our Ravin NE Pad is still under production restriction due to a natural gas pipeline installation delay requiring the flaring of all gas production from this pad. The pipeline is scheduled to be in service within the next two weeks at which point we are expecting normal production operations to be resumed. The Abraxas Raven Rig#1 is scheduled to be started up within the next several months to begin drilling operations on the six well Jore Extension Pad.

Delaware Basin, West Texas

In the Delaware Basin of West Texas, the Company has successfully drilled, completed and started flowback on the two well Creosote Pad in Ward County, where Abraxas now owns an approximate 95% working interest. The Wolfcamp A-1 and A-2 were targeted with a 26 stage fracture treatment (frac) in 5,000' laterals. The one well Hackberry pad has been successfully drilled and a 26 stage fracture treatment in the Wolfcamp A-1 is scheduled to start next Monday. Abraxas owns an approximate 75% working interest in this 5,000' lateral well located in Winkler County. The Company is currently drilling a two well pad, Woodberry, in which we own a 100% working interest. The Woodberry Pad adjoins our Caprito block in Ward County.

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Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist of approximately 21,000 square feet. We own the building which is subject to a real estate lien note.

Other Properties

We own 15.3 acres of land in Atascosa County, Texas, 1.5 acres of land and an office building in Ward County, Texas and an office building and lot in Niobrara County, Wyoming, 50 acres of land in DeWitt County, Texas and 582 acres of land, with shop and office, in McKenzie County, North Dakota.We own 23 vehicles which are used in the field by employees. We also own a workover rig, which is used for servicing our wells. Raven Drilling owns a 2000 HP drilling rig, primarily used for drilling wells in the Williston Basin. In North Dakota, we own three houses and a man-camp to house rig crews.

Item 3. Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2018, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

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

Market Information

Our common stock is traded on The NASDAQ Stock Market under the symbol "AXAS." The following table sets forth certain information as to the high and low sales price quoted for our common stock.

Period		**High**	**Low**
2017			
	First Quarter	$2.99	$1.52
	Second Quarter	2.34	1.45
	Third Quarter	2.10	1.51
	Fourth Quarter	2.55	1.85
2018	First Quarter	$2.75	$2.03
	Second Quarter	3.27	2.11
	Third Quarter	3.23	2.05
	Fourth Quarter	2.45	0.90
2019	Through March 8, 2019	$1.46	$1.01

Holders

As of March 8, 2019, we had 166,934,860 shares of common stock outstanding and approximately 908 stockholders of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, our credit facility prohibits the payment of cash dividends on our common stock.

Performance Graph

Set forth below is a performance graph comparing yearly cumulative total stockholder return on our common stock with (a) the monthly index of stocks included in the Standard and Poor’s 500 Index and (b) a market capitalization weighted index of comparable companies based on 1) companies of similar size, 2) other similar companies in the oil and gas exploration industry, and 3) similar operations in comparable geographies compiled in 2017 by Longnecker & Associates ("L&A"). L&A then analyzed each company based on:

- Market capitalization;
- Revenue;
- Assets;
- Enterprise value; and
- Operational similarities.

Using these criteria, in 2018 the following were the comparable companies utilized in the graph below: Approach Resources, Inc. (AREX), Contango Oil & Gas Company (MCF), Earthstone Energy, Inc. (ESTE), Ring Energy, Inc. (REI) and Rosehill Resources Inc. (ROSE). Halcon Resources Corporation (HK) and Lillis Energy Inc. (LLEX) were added to the list in 2018 based upon the criteria originally utilized by L&A. Gastar Exploration Inc. (GST) and Lonestar Resources US Inc. (LONE) were removed from the list as they were no longer comparable companies due to market capitalization or lack of operational similarities

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All of these cumulative total returns are computed assuming the value of the investment in our common stock and each index as $100.00 on December 31, 2013, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2014, 2015, 2016, 2017 and 2018.

	12/31/2013	**12/31/2014**	**12/31/2015**	**12/31/2016**	**12/31/2017**	**12/31/2018**
Small Cap Index - New Peer Group	$ 100.00	$ 46.56	$ 7.37	$ 3.26	$ 2.91	$ 0.92
Small Cap Index - Old Peer Group	$ 100.00	$ 46.18	$ 26.02	$ 35.27	$ 28.57	$ 16.73
S&P 500	$ 100.00	$ 111.39	$ 110.58	$ 121.13	$ 144.65	$ 135.63
AXAS	$ 100.00	$ 90.16	$ 32.51	$ 78.81	$ 75.44	$ 33.43

The information contained above under the caption “Performance Graph” is being “furnished” to the SEC and shall not be deemed to be “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate it by reference into such filing.

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Item 6. Selected Financial Data

The following selected financial data is derived from our Consolidated Financial Statements as of and for the years ended December 31, 2014 through 2018. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto and other financial information included herein. See “Financial Statements and Supplementary Data” in Item 8.

	Year Ended December 31,				
	2014	2015	2016	2017	2018
	(In thousands, except per share data)				
Total revenue - continuing operations	$133,776	$67,030	$56,555	$86,264	$149,167
Net income (loss)	$63,269	$(127,110)	$(96,378)	$16,006	$57,821
Net income (loss) from continuing operations	$61,951	$(127,090) (2)	$(96,378) (3)	$16,006	$57,821
Net income (loss) from discontinued operations - net of tax	$1,318 (1)	$(20)	$-	$-	$-
Net income (loss) per common share - diluted - continuing operations	$0.61	$(1.21)	$(0.79)	$0.10	$0.34
Weighted average shares outstanding - Diluted	101,468	104,605	122,132	162,844	167,689
Total assets	$374,899	$267,872	$161,648	$273,806	$425,890
Long-term debt, excluding current maturities	$76,554	$138,402	$96,616	$87,354	$183,091
Total stockholders' equity	$207,495	$84,465	$18,505	$106,308	$166,510

(1) Includes a gain of $1.9 million on the sale of our Canadian subsidiary.
(2) Includes proved property impairment of $128.6 million.
(3) Includes proved property impairment of $67.6 million.

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

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See “Financial Statements and Supplementary Data” in Item 8.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary acreage acquisitions in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

While we have attained positive net income in three of the last five years, there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

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Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL, and gas prices in the future. The market price of oil and condensate, NGL and gas in 2019 will impact the amount of cash generated from operating activities, which will in turn impact our financial position. As of March 8, 2019, the NYMEX oil and gas price was $56.07 per Bbl of oil and $2.87 per Mcf of gas, respectively.

During 2018, the NYMEX future price for oil averaged $64.98 per barrel as compared to $50.85 per barrel in 2017 and the NYMEX future spot price for gas averaged $3.07 per Mcf compared to $3.14 per Mcf in 2017. Prices closed on December 31, 2018 at $45.41 per Bbl of oil and $2.94 per Mcf of gas. If commodity prices decline from these levels, our revenue and cash flows from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices decline, our revenues, profitability and cash flows from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income. Finally, low commodity prices will likely cause a reduction of the borrowing base under our credit facility. The borrowing base under our credit facility is scheduled to be redetermined on March 28, 2019.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;
- quality of the hydrocarbons; and

- gathering, processing and transportation costs.

The following table sets forth our average differentials for the years ended December 31, 2016, 2017 and 2018:

	Oil			Gas		
	2016	**2017**	**2018**	**2016**	**2017**	**2018**
Average realized price	$37.14	$46.76	$57.59	$1.26	$1.77	$1.71
Average NYMEX price	$43.47	$50.85	$64.98	$2.55	$3.14	$3.07
Differential	$(6.33)	$(4.09)	$(7.39)	$(1.29)	$(1.37)	$(1.36)

(1) Average realized prices are before the impact of hedging activities.

The Company's derivative contracts as of December 31, 2018 consisted of NYMEX-based fixed price swaps and basis differential swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party.

Our hedging arrangements equate to approximately 51% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021. By removing a portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flows from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flows on the portion of the production that has been hedged. We have in the past and will in the future sustain losses on both open and settled derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts. In 2016, we incurred a loss of $18.0 million, consisting of a gain of $1.8 million on closed contracts and a loss of $19.8 million related to open contracts. In 2017, we incurred a loss of $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million related to open contracts. In 2018, we recorded a gain of $8.1 million, consisting of a loss of $19.0 million on closed contracts and a gain of $27.1 million related to open contracts. We have not designated any of these derivative contracts as a hedge as permitted by applicable accounting rules if certain conditions are met.

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The following table sets forth our derivative contracts at December 31, 2018:

	Oil - WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
January - December 2019	2,941	$56.20
January - December 2020	2,204	$54.35
January - December 2021	1,815	$60.32
Basis Swaps		
January - December 2019	4,000	$2.98
January - December 2020	4,000	$2.98

At December 31, 2018, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $15.1 million.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve report as of December 31, 2018, our average annual estimated decline rate for our net proved developed producing reserves is 35%; 19%; 14%; 11% and 9% in 2019, 2020, 2021, 2022 and 2023, respectively, 11% in the following five years, and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

In addition to our ability to successfully drill wells, we must also market our production which depends substantially on the availability, proximity and capacity of gathering systems, pipelines and processing facilities, which are also known as midstream facilities, owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations could be adversely affected. Both of our principal areas of operation (the Bakken and Permian Basin) have experienced substantial development in recent years, and this has made it more difficult for providers of midstream infrastructure and services to keep pace with the corresponding increases in field-wide production. The ultimate timing and availability of adequate infrastructure is not within our control and we could experience capacity constraints for extended periods of time that would negatively impact our ability to meet our production targets. Weather, regulatory developments and other factors also affect the adequacy of midstream infrastructure.

We had capital expenditures during 2018 of approximately $174.0 million. We have a capital expenditure budget for 2019 of approximately $94.5 million. Approximately $46.2 million of the 2019 budget is allocated to continue development of our Permian and Delaware Basin assets and $38.3 million for the continued development of our Bakken/Three forks play in North Dakota. The remaining amount is allocated to acquisitions, facilities and other. The 2019 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources including under our credit facility, the results of our exploitation efforts, our financial results and our ability to obtain permits for drilling locations.

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The following table presents historical net production volumes for the years ended December 31, 2016, 2017 and 2018:

	2016	2017	2018
Total Production (Mboe)	2,262	2,698	3,580
Average daily production (Boepd)	6,181	7,391	9,809
% Oil	61 %	58 %	64 %

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flows from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing of derivative instruments, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of December 31, 2018, we had approximately $20.0 million of availability under our credit facility. As of March 8, 2019, we had approximately $20.0 million available under our credit facility. The availability under our credit facility is subject to a borrowing base determined by our lenders. This borrowing base is subject to semi-annual redeterminations. The next redetermination becomes effective on March 28, 2019.

Borrowings and Interest. At December 31, 2018, we had a total of $180.0 million outstanding under our credit facility and total indebtedness of $183.4 million (including the current portion). As of March 8, 2019, we had a total of $180.0 million outstanding under our credit facility and total indebtedness of $183.3 million (including the current portion). If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

Exploration and Development Activity. We believe that our asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2018, we operated properties comprising approximately 96% of the Boe's of our estimated net proved reserves, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2018, we drilled or participated in 122 gross (60.4 net) wells of which 98% were commercially productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flows from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 63% of our estimated proved reserves on a Boe basis at December 31, 2018 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Results of Operations

Selected Operating Data. The following table sets forth operating data for the periods presented.

	Year Ended December 31, (in thousands, except per unit data)		
	2016	**2017**	**2018**
Operating revenue (1):			
Oil sales	$50,965	$73,584	$132,904
Gas sales	3,978	6,898	7,854
NGL sales	1,550	5,707	8,272
Other income	62	75	137
Total revenues	$56,555	$86,264	$149,167
Operating (loss) income	$(73,878)	$20,886	$57,528
Oil sales (MBbls)	1,372	1,574	2,308
Gas sales (MMcf)	3,160	3,889	4,587
NGL sales (MBbls)	363	476	508
Oil equivalents (MBoe)	2,262	2,698	3,580
Average oil sales price (per Bbl)(1)	$37.14	$46.76	$57.59
Average gas sales price (per Mcf)	$1.26	$1.77	$1.71
Average NGL price (per Bbl)	$4.27	$11.99	$16.28
Average oil equivalent sales price (per Boe)	$24.97	$31.95	$41.62

(1) Revenue and average sales prices are before the impact of hedging activities.

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Comparison of Year Ended December 31, 2018 to Year Ended December 31, 2017

Revenue. During the year ended December 31, 2018, revenue increased to $149.2 million from $86.3 million in 2017. The increase in revenue was primarily due to higher oil and NGL prices in 2018 as well as higher sales volumes in 2018 for all products as compared to 2017. Higher commodity prices added $26.9 million to revenue, while higher sales volumes contributed $36.0 million to revenue in 2018. During 2018 we experienced an increase in the average realized oil price of approximately 23% from 2017 levels. Average realized gas prices decreased by approximately 3% and average realized NGL prices increased by approximately 36% from 2017 levels. Gas and NGL sales were negatively impacted by pipeline constraints in the Permian and Rocky Mountain regions during 2018.

Oil sales volumes increased to 2,308 MBbls for the year ended December 31, 2018 from 1,574 MBbls for the same period of 2017. The increase in oil sales volumes was due to new production brought on line offset by natural field declines and sales of non-core properties. New production brought on line added 665 MBoe to sales in 2018. Gas sales volumes increased to 4,587 MMcf for the year ended December 31, 2018 from 3,889 MMcf for the year ended December 31, 2017. The increase in gas sales volumes was primarily due to new wells brought on line as well as the acquisition of additional interests in existing wells. New wells brought onto production contributed 574 MMcf to production for the year ended December 31, 2018. NGL sales increased to 508 MBbls for the year ended December 31, 2018 from 476 MBbls for the same period of 2017. The increase in NGL sales was primarily due to increased gas production from fields in West Texas and North Dakota that have a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the year ended December 31, 2018 increased to $24.3 million from $15.2 million in 2017. The increase in LOE was primarily due to higher cost of services and new wells brought onto production during 2018 as well as higher cost incurred shutting in wells for frac protect and repairing wells damaged by frac hits from offset wells. LOE per Boe for the year ended December 31, 2018 was $6.79 compared to $5.63 for the same period of 2017. The increase in LOE per Boe was attributable to higher costs which were somewhat offset by higher sales volumes in 2018 as compared to 2017**.**

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2018 increased to $12.0 million from $7.2 million in 2017. The increase was primarily due to higher realized prices and sales volumes in 2018 as compared to 2017. Production and ad valorem taxes as a percentage of oil and gas revenue remained constant at 8% in 2018 and 2017.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, decreased to $9.7 million for the year ended December 31, 2018 from $13.0 million in 2017. The decrease in 2018 was primarily due to incentive bonuses accrued in 2017 as well as a one-time discretionary bonus paid in 2017. G&A expense per Boe was $2.70 for the year ended December 31, 2018 compared to $4.83 for the same period of 2017. The decrease in per Boe was the result of the decrease in G&A expenses as well as the increase in production in 2018 as compared to

2017.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation decreased to $2.4 million for the year ended December 31, 2018 compared to $3.2 million for the same period of 2017. The decrease was primarily due stock based compensation relating to stock options being fully amortized prior to 2018.

Depreciation, Depletion, and Amortization ("DD&A") Expenses. DD&A expense excluding accretion, increased to $42.8 million for the year ended December 31, 2018 from $26.2 million in 2017. DD&A expense increased primarily due to higher future development costs included in the December 31, 2018 reserve report, based on current development program, as well as higher production volumes in 2018 as compared to 2017. DD&A per Boe for 2018 was $11.94 compared to $9.72 in 2017. The increase in DD&A expense per Boe was primarily due to a higher full cost pool as well as higher future development costs in 2018 as compared to 2017 and higher capital cost in relation to reserve additions.

Interest Expense. Interest expense increased to $7.1 million in 2018 from $2.5 million for 2017. The increase was primarily due to higher debt levels in 2018 as compared to 2017, as well as higher interest rates in 2018 as compared to 2017. In 2018 the interest rate on our credit facility averaged 5.4% as compared to 4.1% in 2017.

Income Taxes. Due to loss carry forwards, we did not recognize any income tax expense for the years ended December 31, 2018 and 2017.

(Gain) loss on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and by periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts as prescribed by Accounting Standards Codification 815, Derivatives and Hedging "ASC 815"; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of fixed price swaps and basis differential swaps in 2018 and fixed price swaps and basis differential swaps and collar contracts in 2017. The net estimated value of our commodity derivative contracts was an asset of approximately $15.1 million as of December 31, 2018. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year-ended December 31, 2018, we recognized a gain of $8.1 million, consisting of a loss of $19.0 million on closed contracts and a gain of $27.1 million on the mark to market valuation on open contracts. For the year ended December 31, 2017, we incurred a loss on our derivative contracts of approximately $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million on the mark to market valuation of open contracts.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flows from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2018 and 2017, the net capitalized cost of our oil and gas properties did not exceed the future net revenues from our estimated proved reserves. The year-end amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2018 which were $59.65 per Bbl of oil and $1.76 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves. The twelve month first-day-of-the-month average oil and gas prices for the year ended 2017 were $46.83 per Bbl for oil and $1.79 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

Comparison of Year Ended December 31, 2017 to Year Ended December 31, 2016

Revenue. During the year ended December 31, 2017, revenue increased to $86.3 million from $56.6 million in 2016. The increase in revenue was primarily due to higher commodity prices in 2017 as well as higher sales volumes in 2017 as compared to 2016. Higher commodity prices added $20.8 million to revenue, while higher sales volumes contributed $8.9 million to revenue in 2017. During 2017 we experienced an increase in the average realized oil price of approximately 26% from 2016 levels. Average realized gas prices increased by approximately 41% and average realized NGL prices increased by approximately 181% from 2016 levels.

Oil sales volumes increased to 1,574 MBbls for the year ended December 31, 2017 from 1,372 MBbls for the same period of 2016. The increase in oil sales volumes was due to new production brought on line offset by natural field declines and sales of non-core properties. New production brought on line added 538 MBoe to sales in 2017. Gas sales volumes increased to 3,889 MMcf for the year ended December 31, 2017 from 3,160 MMcf for the year ended December 31, 2016. The increase in gas sales volumes was primarily due to new wells brought on line as well as the acquisition of additional interests in existing wells. New wells brought onto production contributed 601 MMcf to production for the year ended December 31, 2017. NGL sales increased to 476 MBbls for the year ended December 31, 2017 from 363 MBbls for the same period of 2016. The increase in NGL sales was primarily due to increased gas production from fields in West Texas and North Dakota that have a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the year ended December 31, 2017 decreased to $15.2 million from $18.2 million in 2016. The decrease in LOE was primarily due to our focus on lowering LOE and shutting in marginal wells as well as the sale of non-core properties. LOE per Boe for the year ended December 31, 2017 was $5.63 compared to $8.05 for the same period of 2016. The decrease in LOE per Boe was attributable to lower cost as well as higher sales volumes in 2017 as compared to 2016.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2017 increased to $7.2 million from $5.5 million in 2016. The increase was primarily due to higher realized prices and sales volumes in 2017 as compared to 2016. Production and ad valorem taxes as a percentage of oil and gas revenue decreased to 8% in 2017 as compared to 10% in 2016. The decrease in the percentage of oil and gas revenue was primarily due to increased production in Texas which has lower production tax rates than the other states in which we operate.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased to $13.0 million for the year ended December 31, 2017 from $10.4 million in 2016. The increase was primarily due to incentive bonuses accrued in 2017 as well as a one-time discretionary bonus paid in 2017. G&A expense per Boe was $4.83 for the year ended December 31, 2017 compared to $4.58 for the same period of 2016.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation was consistent at $3.2 million for the years ended December 31, 2017 and 2016. There were no significant grants of stock options or restricted stock in 2017.

Depreciation, Depletion, and Amortization ("DD&A") Expenses. DD&A expense, excluding accretion, increased to $26.2 million for the year ended December 31, 2017 from $24.4 million in 2016. DD&A expense increased primarily due to higher future development costs included in the December 31, 2017 reserve report as well as higher production volumes in 2017 as compared to 2016. DD&A per Boe for 2017 was $9.72 compared to $10.80 in 2016. The decrease in DD&A expense per Boe was primarily due to a higher reserve volumes in 2017 as compared to 2016.

Interest Expense. Interest expense decreased to $2.5 million in 2017 from $3.8 million for 2016. The decrease was primarily due to lower debt levels in 2017 as compared to 2016, partially offset by higher interest rates in 2017 as compared to 2016.

Income Taxes. Due to losses incurred and loss carry forwards, we did not recognize any income tax expense for the years ended December 31, 2017 and 2016.

(Gain) loss on Derivative Contracts. Our derivative contracts consisted of fixed price swaps, basis differential swaps and collar contracts in 2017 and 2016. The net estimated value of our commodity derivative contracts was a liability of approximately $13.2 million as of December 31, 2017. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year ended December 31, 2017, we incurred a loss on our derivative contracts of approximately $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million on the mark to market valuation of open contracts. For the year-ended December 31, 2016, we incurred a loss of $18.0 million, consisting of a gain of $1.8 million on closed contracts and a loss of $19.8 million related to open contracts.

Monetization of Derivative Contracts. During 2016, we monetized certain of our derivative contracts. Proceeds from the monetization were approximately $14.4 million. We did not monetize any derivative contracts in 2017.

Ceiling Limitation Write-Down. During 2016, we incurred impairments of $67.6 million. As of December 31, 2017, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. The year-end amount was calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2017 which were $46.83 per Bbl for oil and $1.79 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

Liquidity and Capital Resources

General. The oil and gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following:

- the development and exploration of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional oil and gas properties; and
- production and gathering facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties. In addition In January 2019, we announced that we had engaged Petrie Partners to assist us in identifying and assessing our options for our Bakken properties. We are still early in this process and do not know the ultimate outcome. In the event that this process were to result in the sale of our Bakken properties, we believe that the proceeds would be used to significantly pay down or fully retire our debt, support our Raven No. 1 rig in the Delaware Basin until it achieves free cash flow and possibly buy back stock. We feel that the cash flow from these sources will be adequate to fund our operations into the future, long and short term.

Our principal sources of capital are cash flows from operations, borrowings under our credit facility, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financings on terms acceptable to us, if at all. We believe that our cash flow from these sources going forward, will be adequate to fund our operations

Operating Cash Flow. Our operating cash flow is sensitive to many variables, the most volatile of which is the prices of the oil, gas and NGL we produce and sell. Our consolidated cash flow from operations increased in 2018, primarily due to increased oil and NGL prices and increased sales volumes for all products during the year ended December 31, 2018 as compared to 2017. We expect cash flows from operations to continue to be a primary source of liquidity in 2019.

Commodity Prices. Prices are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors, which are difficult to predict, create volatility in prices and are beyond our control. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 51% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021.

The material terms of our derivative financial instruments as of December 31, 2018 are presented in Note 11 in "Item 8. Financial Statements and Supplementary Data" of this report.

Commodity prices can also affect our operating cash flows through an indirect effect on operating expenses. Significant commodity price decreases can lead to a decrease in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also decrease, causing a positive impact on our cash flows as the prices paid for services and equipment decline.

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Working Capital (Deficit). At December 31, 2018, our current liabilities of $64.4 million exceeded our current assets of $50.7 million resulting in a working capital deficit of $13.7 million. This compares to a working capital deficit of $34.4 million at December 31, 2017. Current assets at December 31, 2018 primarily consisted of cash of $0.9 million, accounts receivable of $39.6 million, current amount of our derivative asset of $9.6 million and other current assets of $0.6 million. Current liabilities at December 31, 2018 primarily consisted of trade payables of $39.6 million, revenues due third parties of $23.1 million, current maturities of long-term debt of $0.3 million, the current amount of our derivative liability of $0.6 million and accrued expenses of $0.8 million. The working capital deficit is expected to be funded by cash flows from operations and borrowings under our credit facility.

Capital Expenditures. Capital expenditures in 2016, 2017 and 2018 were $31.7 million, $135.1 million, and $174.0 million, respectively. Expenditures in 2017 included non-cash expenditures of $26.8 million, (which consisted of 2.0 million shares of our common stock issued in connection with an acquisition in August 2017, all of our interest in the surface estate of Coyanosa Draw Ranch and one-half of the mineral interests under the Coyanosa Draw Ranch). The table below sets forth the components of these capital expenditures:

	Years Ended December 31,		
	2016	**2017**	**2018**
	(in thousands)		
Expenditure category:			
Exploration/Development	$30,787	$102,987	$131,271
Acquisitions	-	31,409	41,465
Facilities and other	876	682	1,230
	$31,663	$135,078	$173,966

During 2016 capital expenditures were primarily for exploration and for the development of our existing properties. During 2017 and 2018, capital expenditures were for the exploration and development of our existing properties and acquisition of additional leasehold. Expenditures in 2017 included non-cash expenditures of $26.8 million, (which consisted of 2.0 million shares of our common stock issued in connection with an acquisition in August 2017, all of our interest in the surface estate of Coyanosa Draw Ranch and one-half of the mineral interests under the Coyanosa Draw Ranch). We anticipate making capital expenditures in 2019 of approximately $94.5 million, of which approximately $46.2 million is allocated to acquiring additional acreage and developing our Bone Spring/Wolfcamp acres in the Permian/Delaware Basin. The 2019 budget also allocates approximately $38.3 million for developing our Williston Basin/Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. The 2019 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, our financial results and our ability to obtain permits for drilling locations. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows from operations will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

Sources and Uses of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Years Ended December 31,		
	2016	2017	2018
	(in thousands)		
Net cash provided by operating activities	$26,872	$38,123	$80,000
Net cash used in investing activities	(14,071)	(91,053)	(176,204)
Net cash (used in) provided by financing activities	(16,341)	54,548	95,453
	$(3,540)	$1,618	$(751)

Operating activities for the year ended December 31, 2018 provided $80.0 million in cash, primarily due to higher net income due to higher oil and NGL prices and higher sales volumes for all products. Investing activities used $176.2 million in 2018 primarily for the development of our existing properties and leasehold acquisitions. Cash expenditures for the year ended December 31, 2018 included a decrease in the accounts payable balance related to capital expenditures of $6.0 million, and a decrease in our asset retirement obligation liability of $1.8 million, resulting in actual capital expenditures, net of dispositions, incurred during the period of $168.4 million. Financing activities provided $95.4 million primarily from net borrowings under our credit facility.

Operating activities for the year ended December 31, 2017 provided $38.1 million in cash. Increased net income, due to higher prices and volumes and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $91.1 million primarily for the development of our existing properties. Financing activities provided $54.5 million primarily from the proceeds from the issuance of 28.8 million shares of common stock in January 2017, resulting in net proceeds of $65.2 million, offset primarily by reductions of the amount due under our credit facility.

Operating activities for the year ended December 31, 2016 provided $26.9 million in cash. Net changes in operating assets and liabilities and the monetization of derivative positions accounted for most of these funds. Investing activities used $14.1 million primarily for the development of our existing properties. Financing activities used $16.3 million primarily for reductions of the amount due under our credit facility, offset by long term borrowings and proceeds from the issuance of 28.8 million shares of common stock in May 2016, resulting in net proceeds of $27.1 million.

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Future Capital Resources. Our principal sources of capital going forward, for 2019 and beyond, are cash flows from operations, borrowings under our credit facility, proceeds from the sale of properties, monetizing of derivative instruments and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease in commodity prices from current levels would likely reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flows from operations and the amount that we are able to borrow under our credit facility will also decline. As of December 31, 2018 we had availability under our credit facility of $20.0 million The availability under our credit facility is subject to a borrowing base determined by our lenders. This borrowing base is subject to semi-annual redeterminations. The next redetermination becomes effective on March 28, 2019. The risk of not finding commercially productive reservoirs will be compounded by the fact that 63% of our total estimated proved reserves on a Boe basis at December 31, 2018 were classified as undeveloped.

Contractual Obligations. We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2018:

	Payments due in the twelve month periods ended:				
Contractual Obligations (In thousands)	**Total**	**December 31, 2019**	**December 31, 2020-2021**	**December 31, 2022-2023**	**Thereafter**
Long-term debt (1)	$183,358	$ 267	$ 180,575	$ 2,516	$ -
Interest on long-term debt (2)	26,265	10,960	15,130	175	-
Total	$209,623	$ 11,227	$ 195,705	$ 2,691	$ -

(1) These amounts represent the balances outstanding under our credit facility and the real estate lien note. These payments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of long-term debt at December 31, and current effective interest rates at that time.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2018, our reserve for these obligations totaled $7.5 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

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Off-Balance Sheet Arrangements. At December 31, 2018, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have, or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2018, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Long-Term Indebtedness.

Long-term debt consisted of the following:

	2017	**2018**
	(In thousands)	
Senior secured credit facility	$84,000	$180,000
Real estate lien note	3,616	3,358
	87,616	183,358
Less current maturities	(262)	(267)
Total	$87,354	$183,091

Credit Facility

The Company has a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of December 31, 2018, $180.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At December 31, 2018, the Company had a borrowing base of $200.0 million. The borrowing base is determined semi-annually by the lenders based upon the Company's reserve reports, one of which must be prepared by its independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of the Company's proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and the Company is able to request one redetermination during any six-month period between scheduled redeterminations.

Outstanding borrowings in excess of the borrowing base must be repaid immediately or the Company must pledge additional oil and gas properties or other assets as collateral. The Company does not currently have any substantial unpledged assets and it may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause the Company to fail to be in compliance with the financial covenants described below. The Company's borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of its then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. The Company's borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (i) 1.5%-2.5%, depending on the utilization of the borrowing base, or (ii) if we elect, LIBOR plus, in each case, 2.5%-3.5% depending on the utilization of the borrowing base. At December 31, 2018, the interest rate on the credit facility was approximately 6.0% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is May 16, 2021. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the credit facility and is able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of the Company's subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of the Company's proven reserves. The Company has also granted its lenders a security interest in our headquarters building.

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Under the credit facility, the Company is subject to customary covenants, including certain financial covenants and reporting requirements. The Company is required to maintain a current ratio, as defined in the credit facility, as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00. The Company is also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 3.50 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is defined as the sum of consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts plus expenses incurred in connection with the negotiation, execution, delivery and performance of the credit facility plus expenses incurred in connection with any acquisition permitted under the credit facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses minus all non-cash items of income which were included in determining consolidated net loss, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the headquarters building and obligations with respect to surety bonds and derivative contracts.

At December 31, 2018, we were in compliance with the interest coverage ratio and the total debt to EBITDAX ratio and received a waiver with respect to our non-compliance with the current ratio. As of December 31, 2018, the interest coverage ratio was 11.94 to 1.00, the total debt to EBITDAX ratio was 2.14 to 1.00, and our current ratio was 0.96 to 1.00. We have received a waiver for the non-compliance with the current ratio which related only to compliance at December 31, 2018.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;

- transfer or sell assets;

- create liens on assets;

- engage in transactions with affiliates other than on an "arm's length" basis;

- make any change in the principal nature of our business; and

- permit a change of control.

The credit facility also contains certain additional covenants including:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and

- if the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities. As of December 31, 2018, we were in compliance, or have obtained waiver for, all of the terms of our credit facility.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note was modified on June 20, 2018 to a fixed rate of 4.9% and is payable in monthly installments of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2017, and 2018, $3.6 million and $3.4 million, respectively, were outstanding on the note.

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Net Operating Loss Carryforwards

At December 31, 2018, we had, subject to the limitation discussed below, $245.2 million of pre 2018 NOLs for U.S. tax purposes and a $46.8 million NOL for 2018. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018, can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10 “Income Taxes”. Therefore, we have established a valuation allowance of $67.3 million for deferred tax assets at December 31, 2018.

Related Party Transactions

We have adopted a policy that transactions between us and our officers, directors, principal stockholders, or affiliates of any of them, will be on terms no less favorable to us than can be obtained on an arm’s length basis in transactions with third parties and must be approved by our audit committee. There were no related party transactions in 2016, 2017 or 2018.

Critical Accounting Policies

The preparation of financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Full Cost Method of Accounting for Oil and Gas Activities. SEC Regulation S-X Rule 4-10 and ASC 932 defines the financial accounting and reporting standards for companies engaged in oil and gas activities. Two methods are prescribed: the successful efforts method and the full cost method. We have chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities but do not include any costs related to production, general corporate overhead or similar activities. Sales of oil and gas properties are treated as a reduction of the full cost pool with no gain or loss being recognized, except under certain circumstances. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and gas properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and gas properties under the successful efforts method. As a result, our financial statements will differ from those of companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our oil and gas properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years. Our oil and gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from impairment testing procedures associated with the full cost method of accounting as discussed below.

Under full cost accounting rules, the net capitalized cost of oil and gas properties, less related deferred taxes, may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves on a pool by pool basis, discounted at 10%, plus the lower of cost or fair market value of unproved properties and the cost of properties not being amortized, less income taxes. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flows from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are depressed. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

Estimates of Proved Oil and Gas Reserves. Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved oil and gas reserves have been estimated by our engineering and operations departments and assisted by an independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2016, and 2017 and LaRoche Petroleum Consultants as of December 31, 2018. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

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You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on costs on the date of the estimate and for the years ended December 31, 2016, 2017 and 2018 oil and gas prices were based on the average 12-month first-day-of-the-month pricing. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Asset Retirement Obligations. The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense.

Accounting for Derivatives. Gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. We have elected not to apply hedge accounting to our derivative contracts. As a result, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. Our derivative contracts consisted of fixed price swaps, basis differential swaps and collar contracts in 2017. In 2018 our derivative contracts consisted of fixed price swaps and basis differential swaps. Due to the volatility of oil and gas prices, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2017, and 2018, the net market value of our commodity derivatives was a net liability of $13.2 million and an asset of $15.1 million, respectively.

New Accounting Standards and Disclosures.

See Note 1, "Organization and Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a discussion of new accounting requirements.

In February 2016, the FASB issued new guidance in ASC 842, *Leases* ("ASC 842"), which will supersede the current guidance in ASC 840, *Leases* ("ASC 840"). The core principle of the new guidance is that a lessee should recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for leases currently classified as operating leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. In January 2018, the FASB issued new guidance in ASC 842 to provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840.

In July 2018, the FASB issued new guidance in ASC 842 to provide entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with ASC 840. An entity that elects this transition method must provide the required ASC 840 disclosures for all periods that continue to be reported in accordance with ASC 840.

The amendments in these ASUs are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption was permitted. The Company expects to adopt ASU 2016-02 retrospectively in the first quarter of 2019 (that is, the initial period of adoption) through a cumulative-effect adjustment to the opening balance of retained earnings. At transition, the Company plans to apply the package of practical expedients provided in ASC 842 that allow companies, among other things, to not reassess contracts that commenced prior to adoption.

The Company has a team, including third-party consultants, to implement the standard and is implementing a software solution that will be used to track and account for its leases under ASC 842 on an ongoing basis. The primary effect on the Company's consolidated financial statements will be to record a right-of-use (ROU) asset and lease liability on the balance sheet for all leases with terms at commencement that are greater than twelve months. Leases will be classified as either finance or operating, with that classification affecting the pattern of expense recognition in the income statement.

The Company enters into certain lease agreements in support of its operations for assets such as compressors, a drilling rig, employee housing and office equipment. As of December 31, 2018, the Company does not anticipate that the adoption and implementation of ASC 842 will result in material changes in assets and liabilities on the consolidated balance sheet in 2019, and will not result in a material impact to the consolidated statement of operations.

The Company has made certain accounting policy decisions including that it plans to adopt the short-term lease recognition exemption, account for certain asset classes and has established a balance sheet recognition capitalization threshold. The Company also expects for certain lessee asset classes to elect the practical expedient to not separate lease and non-lease components. For these asset classes, the agreements will be accounted for as a single component.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flows from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indices fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2018, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flows by approximately $14.9 million for the year. If commodity prices remain at their current levels the impact on operating revenues and cash flows, could be much more significant. However, we do have derivative contracts in place that will mitigate the impact of low commodity prices.

Derivative Instrument Sensitivity

At December 31, 2018, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $15.1 million. The fair market value of our commodity derivative contracts is sensitive to changes in the market price for oil and gas. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses.

If oil prices decline by $1.00 per Bbl, then the present value of estimated future net revenues from proved reserves of December 31, 2018 would decline by $18.9 million, or 2.8%. If natural gas prices decline by $0.10 per Mcf, then the present value of estimated future net revenues from proved reserves as of December 31, 2018 would decline by $2.3 million, or 0.3%. However, larger decreases in oil and natural gas prices may have a disproportionate impact on the present value of estimated future net revenues from proved reserves.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of December 31, 2018, we had $180.0 million of outstanding indebtedness under our credit facility with a variable interest rate. At December 31, 2018, the interest rate on the credit facility was approximately 6.0% based on 1-month LIBOR borrowings and level of utilization. An increase in the interest rate of 1% would increase our interest expense by $1.8 million on an annual basis, based on the outstanding balance at December 31, 2018.

Item 8. Financial Statements and Supplementary Data

For the financial statements and supplementary data required by this Item 8, see the Index to Consolidated Financial Statements.

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

None.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”)). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer believe that the disclosure controls and procedures as of December 31, 2018 were effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and are effective to ensure that information required to be disclosed by us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the fourth quarter of 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and implemented by the Company's Board of Directors, management and other personnel, 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 and 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.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by BDO USA, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information

None.

PART III

Item10. Directors, Executive Officers and Corporate Governance

There is incorporated in this Item 10 by reference to that portion of our definitive proxy statement for the 2019 Annual Meeting of Stockholders which appears therein under the caption “Election of Directors – Board of Directors,” “– Code of Ethics,” “– Committees of the Board of Directors.” and Executive Officers.

Audit Committee and Audit Committee Financial Expert

The Audit Committee of our board of directors consists of Brian L. Melton., W. Dean Karrash, Paul A. Powell, Jr. and Jerry J. Langdon. The board of directors has determined that each of the members of the Audit Committee is independent as determined in accordance with the listing standards of The NASDAQ Stock Market and Item 407(a) of Regulation S-K. In addition, the board of directors has determined that Brian L. Melton and W. Dean Karrash, as defined by SEC rules, are audit committee financial experts.

Section 16(a) Compliance

Section 16(a) of the Exchange Act requires our directors and executive officers and persons who own more than 10% of a registered class of Abraxas equity securities to file with the SEC and The NASDAQ initial reports of ownership and reports of changes in ownership of Abraxas common stock. Officers, directors and greater than 10% stockholders are required by SEC regulations to furnish us with copies of all such forms they file. Based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all our directors and executive officers complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act during 2018.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2019 Annual Meeting of Stockholders which appears therein under the captions “Election of Directors – Committees of the Board of Directors” and “Executive Compensation.”

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

There is incorporated in this Item 12 by reference that portion of our definitive proxy statement for the 2019 Annual Meeting of Stockholders which appears therein under the caption “Securities Holdings of Principal Stockholders, Directors, Nominees and Officers.”

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

There is incorporated in this Item 13 by reference that portion of our definitive proxy statement for the 2019 Annual Meeting of Stockholders which appears therein under the captions “Certain Relationships and Related Party Transactions” and “Election of Directors – Director Independence.”

Item 14. Principal Accountant Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2019 Annual Meeting of Stockholders which appears therein under the caption “Principal Auditor Fees and Services.”

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)1. Consolidated Financial Statements

(a)2. Financial Statement Schedules

All schedules have been omitted because they are not required, not applicable, or the information required is included in the Consolidated Financial Statements or related notes thereto.

(a)3. Exhibits

The following Exhibits have previously been filed by the Registrant or are included following the Index to Exhibits.

Exhibit

Number Description

3.1 Articles of Incorporation of Abraxas dated August 30, 1990. (Filed as Exhibit 3.1 to our Registration Statement on Form S-4, No. 33-36565. (the "S-4 Registration Statement")).

3.2	Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement).
3.3	Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement).
3.4	Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to our Registration Statement on Form S-3, No. 333-00398).
3.5	Articles of Amendment to the Articles of Incorporation of Abraxas dated as of August 12, 2000. (Filed as Exhibit 3.5 to our Annual Report on Form 10-K filed on April 2, 2001).
3.6	Certificate of Correction dated February 24, 2011 (Filed as Exhibit 3.6 to our Annual Report on Form 10-K filed on March 15, 2012).
3.7	Certificate of Withdrawal dated March 16, 2015. (Filed as Exhibit 3.6 to our Current Report on Form 8-K filed March 17, 2015).
3.8	Certificate of Amendment to Articles of Incorporation dated May 9, 2017. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on May 10, 2017).
3.9	Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on December 18, 2018).
4.1	Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).

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4.2	Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to our Annual Report on Form 10-K filed on March 31, 1995).
*10.1	Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to our Registration Statement on Form S-4, No. 333-18673 filed on December 24, 1996).
*10.2	Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.4 to our Annual Report on Form 10-K filed March 14, 2007).
*10.3	Form of Employment Agreement for Executive Officers (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on December 18, 2018).
*10.5	Amended and Restated Abraxas Petroleum Corporation Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Appendix B to our Proxy Statement filed on April 2, 2015).
*10.6	Form of Stock Option Agreement under the Abraxas Petroleum Corporation Amended and Restated 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed June 6, 2005).
*10.7	Abraxas Petroleum Corporation Senior Management Incentive Bonus Plan 2006. (Filed as Exhibit 10.17 to our Annual Report on Form 10-K filed March 23, 2006).
*10.8	Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Appendix A to our Proxy Statement filed on April 3, 2017).
*10.9	Form of Employee Stock Option Agreement under the Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed August 26, 2006).
*10.10	Form of Restricted Stock Agreement under the Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (Filed as Exhibit 10.1 to our Annual Report on Form 10-K filed on March 13, 2015).
*10.11	Form of Restricted Stock Award Agreement under Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on April 6, 2018).

10.13	Promissory Note dated November 13, 2008 by Abraxas Properties Incorporated and Abraxas Petroleum Corporation, payable to the order of Plains Capital Bank, as Lender. (Filed as Exhibit 10.1 to our Current Report on Form 10-Q filed on August 8, 2014.)
10.14	Second Modification, Renewal and Extension of Promissory Note and Deed of Trust Liens by and between Plains Capital Bank, Abraxas Properties Corporation and Abraxas Petroleum Corporation effective March 13, 2013. (Previously filed as Exhibit 10.2 to our Current Report on Form 10-Q filed on August 8, 2014).

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10.15	Third Modification, Renewal and Extension of Promissory Note and Deed of Trust Liens by and between Plains Capital Bank, Abraxas Properties Incorporated and Abraxas Petroleum Corporation effective as of July 13, 2013. (Previously filed as Exhibit 10.3 to our Current Report on Form 10-Q filed on August 8, 2014).
10.16	Amendment No. 2 to Third Amended and Restated Credit Agreement dated as of April 20, 2016 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender (Previously filed as Exhibit 10.1 to our Current Report on Form 8-K filed on April 20, 2016).
10.17	Amendment No. 3 to Third Amended and Restated Credit Agreement dated as of May 16, 2017 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender. (Previously filed as Exhibit 10.1 to our Current Report on Form 8-K filed on May 17, 2017).
14.1	Abraxas Petroleum Corporation Code of Business Conduct and Ethics. (Filed as Exhibit 14.1 to our Annual Report on Form 10-K filed March 22, 2006).
21.1	Subsidiaries of Abraxas. (Previously filed as Exhibit 21.1 to our Annual Report on Form 10-K filed on March 15, 2016).
23.1	Consent of BDO USA, LLP. (Filed herewith).
23.2	Consent of LaRoche Petroleum Consultants. (Filed herewith).
23.3	Consent of DeGolyer and MacNaughton. (Filed herewith).
31.1	Certification – Chief Executive Officer. (Filed herewith).
31.2	Certification – Chief Financial Officer. (Filed herewith).
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).
32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).
99.1	Report of with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).

* Management Compensatory Plan or Agreement.

Item 16. 10-K Summary

None

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Abraxas Petroleum Corporation

San Antonio, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation (the “Company”) and subsidiaries as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company and subsidiaries at December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three 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 *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) and our report dated March 15, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated 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 audits to obtain reasonable assurance about whether the consolidated 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 consolidated 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 regarding the amounts and disclosures in the consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2003.

San Antonio, Texas

March 15, 2019

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Abraxas Petroleum Corporation

San Antonio, Texas

Opinion on Internal Control over Financial Reporting

We have audited Abraxas Petroleum Corporation's (the “Company’s”) internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the “COSO criteria”). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated balance sheets of the Company and subsidiaries as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 15, 2019 expressed an unqualified opinion thereon.

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 “Item 9A, Management’s Annual 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 U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ BDO USA, LLP

San Antonio, Texas

March 15, 2019

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31. 2017	2018
	(In thousands, except per share/share data)	
Assets		
Current assets:		
Cash and cash equivalents	$1,618	$867
Accounts receivable:		
Joint owners, net	14,218	17,110
Oil and gas production sales	17,789	21,991
Other	86	535
Total accounts receivable	32,093	39,636
Derivative asset - short-term	-	9,602
Other current assets	778	626
Total current assets	34,489	50,731
Property and equipment		
Proved oil and gas properties, full cost method	923,237	1,091,905
Other property and equipment	39,136	39,453
Total	962,373	1,131,358
Less accumulated depreciation, depletion, amortization and impairment	(724,606)	(768,140)
Total property and equipment - net	237,767	363,218
Derivative asset - long term	-	10,527
Deferred financing fees - net	1,285	1,149
Other assets	265	265
Total assets	$273,806	$425,890

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31.	
	2017	**2018**
	(In thousands, except per share/share data)	
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$45,570	$39,571
Joint interest oil and gas production payable	11,502	23,063
Accrued interest	140	335
Other accrued liabilities	539	511
Derivative liabilities - short-term	10,837	616
Current maturities of long-term debt	262	267
Total current liabilities	68,850	64,363
Long-term debt - less current maturities	87,354	183,091
Other liabilities	132	-
Derivative liabilities long-term	2,387	4,434
Future site restoration	8,775	7,492
Total liabilities	167,498	259,380
Commitments and contingencies (Note 9)		
Stockholders' Equity		
Preferred stock, par value $0.01 per share - authorized 1,000,000 shares; - 0- shares issued and outstanding	-	-
Common stock, par value $0.01 per share, authorized 400,000,000 shares; 165,889,901 and 166,713,784 issued and outstanding at December 31, 2017 and 2018, respectively	1,659	1,667
Additional paid-in capital	415,471	417,844
Accumulated deficit	(310,822)	(253,001)
Total stockholders' equity	106,308	166,510
Total liabilities and stockholders' equity	$273,806	$425,890

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2016	2017	2018
	(In thousands, except per share data)		
Revenues:			
Oil	$50,965	$73,584	$132,904
Gas	3,978	6,898	7,854
Natural gas liquids	1,550	5,707	8,272
Other	62	75	137
Total Revenue	56,555	86,264	149,167
Operating costs and expenses			
Lease operating	18,205	15,197	24,300
Production and ad valorem taxes	5,454	7,228	12,023
Rig expense	664	-	
Depreciation, depletion, amortization and accretion	24,922	26,677	43,275
Proved property impairment	67,626	-	-
General and administrative (including stock-based compensation of $3,194, $3,238 and $2,366, respectively)	13,562	16,276	12,041
Total operating costs and expenses	130,433	65,378	91,639
Operating (loss) income	(73,878)	20,886	57,528
Other (income) expense:			
Interest income	(1)	(1)	(1)
Interest expense	3,828	2,497	7,053
Amortization of deferred financing fees	1,019	423	440
Loss (gain) on derivative contracts	18,028	1,849	(8,060)
Loss (gain) on sale of non-oil and gas assets	(374)	(102)	181
Other	-	214	94
Total other (income) expense	22,500	4,880	(293)
Income (loss) before income tax	(96,378)	16,006	57,821
Income tax (expense) benefit	-	-	-
Net income (loss)	$(96,378)	$16,006	$57,821
Net income (loss) per common share - basic	$(0.79)	$0.10	$0.35
Net income (loss) per common share - diluted	$(0.79)	$0.10	$0.34
Weighted average shares outstanding			
Basic	122,132	161,141	165,635
Diluted	122,132	162,844	167,689

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands except number of shares)

	Common Stock Shares	Amount	Additional Paid in Capital	Accumulated Deficit	Total
Balance at December 31, 2015	106,346,001	$ 1,063	$ 313,852	$ (230,450)	$ 84,465
Net loss	-	-	-	(96,378)	(96,378)
Stock issuance	28,750,000	287	26,848	-	27,135
Stock issued for compensation	41,102	-	40	-	40
Stock-based compensation	-	-	3,194	-	3,194
Stock options exercised	55,716	1	48	-	49
Restricted stock issued, net of forfeitures	(98,802)	-	-	-	-
Balance at December 31, 2016	135,094,017	1,351	343,982	(326,828)	$ 18,505
Net income	-	-	-	16,006	16,006
Stock issuance	28,750,000	288	64,936	-	65,224
Stock issued for acquisition of oil and gas properties	2,000,000	20	3,315	-	3,335
Stock-based compensation	-	-	3,238	-	3,238
Stock options exercised	2,634	-	-	-	-
Restricted stock issued, net of forfeitures	43,250	-	-	-	-
Balance at December 31, 2017	165,889,901	1,659	415,471	(310,822)	106,308
Net income	-	-	-	57,821	57,821
Stock-based compensation	-	-	2,366		2,366
Stock options exercised	150,327	1	13	-	14
Restricted stock issued, net of forfeitures	673,556	7	(6)	-	1
Balance at December 31, 2018	166,713,784	$ 1,667	$ 417,844	$ (253,001)	$ 166,510

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2016	**2017**	**2018**
Operating Activities:			
Net (loss) income	$(96,378)	$16,006	$57,821
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Loss (gain) on sale of non-oil and gas assets	(374)	(102)	181
Net loss (gain) on derivative contracts	18,028	1,849	(8,060)
Net cash settlements received (paid) on derivative contracts	1,790	2,450	(20,241)
Monetization of derivative contracts	14,370	-	-
Depreciation, depletion and amortization	24,431	26,226	42,759
Proved property impairment	67,626	-	-
Amortization of deferred financing fees	1,019	423	440
Accretion of future site restoration	491	451	516
Stock-based compensation	3,194	3,238	2,366
Non-cash compensation	40	-	-
Changes in operating assets and liabilities:			
Accounts receivable	(4,018)	(18,569)	(7,543)
Other assets	627	155	18
Accounts payable	(3,535)	6,231	11,576
Accrued expenses	(439)	(235)	167
Net cash provided by operating activities	26,872	38,123	80,000
Investing Activities			
Capital expenditures, including purchase and development of properties	(31,663)	(108,236)	(179,509)
Proceeds from the sale of oil and gas properties	13,570	16,979	3,279
Proceeds from the sale of non-oil and gas assets	4,022	204	26
Net cash used in investing activities	(14,071)	(91,053)	(176,204)
Financing Activities			
Proceeds from exercise of stock options and restricted stock	49	-	15
Proceeds from issuance of common stock, net of offering cost of $1.6 million and $3.8 million, respectively	27,135	65,224	-
Proceeds from long-term borrowings	22,000	82,000	127,000
Payments of long-term borrowings	(65,330)	(91,786)	(31,258)
Deferred financing fees	(195)	(890)	(304)
Net cash (used in) provided by financing activities	(16,341)	54,548	95,453

(Decrease) increase in cash and cash equivalents	(3,540)	1,618	(751)
Cash and cash equivalents at beginning of period	3,540	-	1,618
Cash and cash equivalents at end of period	$-	$1,618	$867
Supplemental disclosure of cash flow information:			
Interest paid	$3,899	$2,401	$6,858
Income tax paid	$-	$-	$-
Non-cash investing and financing activities			
Change in asset retirement obligation cost and liabilities	$285	$1,252	$1
Properties classified as held for sale	$9,685	$-	$-
Asset retirement obligations associated with property acquisitions and dispositions, net	$(1,832)	$(1,551)	$(1,799)
Issuance of stock for acquisition of oil and gas properties	$-	$3,335	$-
Change in capital expenditures included in accounts payable	$-	$23,507	$(6,014)

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Significant Accounting Policies

Nature of Operations

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States. Our oil and gas assets are located in three operating regions in the United States: the Rocky Mountain, Permian/Delaware Basin and South Texas.

The terms "Abraxas," "Abraxas Petroleum," "we," "us," "our" or the "Company" refer to Abraxas Petroleum Corporation and of its subsidiaries, including Raven Drilling LLC ("Raven Drilling").

Rig Accounting

In accordance with SEC Regulation S-X, no income is recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates holds an ownership, or other economic interest. Any income not recognized as a result of this limitation is credited to the full cost pool and recognized through lower amortization as reserves are produced.

Use of Estimates

The consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of consolidated financial statements in conformity with GAAP 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 consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The most significant estimates pertain to proved oil, gas and NGL reserves and related cash flow estimates used in impairment tests of oil and gas properties, the fair value of assets and liabilities acquired in business combinations, derivative contracts, the provision for income taxes including uncertain tax positions, stock based compensation, asset retirement obligations, accrued oil and gas revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, differentials, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

Reclassifications

Certain prior year balances have been reclassified for consistency with current year classifications. Such reclassifications had no impact on the results of operations or cash flows from operations.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and derivative contracts. Accounts receivable are generally from companies with significant oil and gas marketing or operating activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers. The counterparties to our derivative contracts are the same financial institutions from which we have outstanding debt; accordingly, we believe our exposure to credit risk to these counterparties is currently mitigated in part by this, as well as the current overall financial condition of the counterparties.

The Company maintains any cash and cash equivalents in excess of federally insured limits in prominent financial institutions considered by the Company to be of high credit quality.

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Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits and short-term investments with original maturities of three months or less.

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $0.4 million and $0.5 million at December 31, 2017 and 2018, respectively. The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and gas with all of the Company’s operational activities having been conducted in the U.S. The Company’s current operational activities and the Company’s consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long lived assets located outside the U.S.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, certain direct costs and indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. The impairment calculations do not consider the impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. During 2016 we recorded a proved property impairment of $67.6 million. As of December 31, 2017 and 2018, our capitalized cost of oil and gas properties did not exceed the future net revenue from our estimated proved reserves.

Other Property and Equipment

Other property and equipment are recorded on the basis of cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and improvements are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this report was based on studies performed by our independent petroleum engineers assisted by the engineering and operations departments of Abraxas. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may cause material revisions to the estimate.

In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the unweighted average 12 month first-day-of-month pricing. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact depreciation, depletion and amortization, or DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields.

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are typically in the form of fixed price commodity and basis swaps, which limit the impact of price fluctuations with respect to the Company’s sale of oil and gas. While it is never management’s intention to hold or issue derivative instruments for speculative trading purposes, conditions could arise where actual production is less than estimated which could result in over hedged volumes.

All derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The derivative instruments the Company utilizes are based on index prices that may and often do differ from the actual oil and gas prices realized in its operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for hedge accounting rules as prescribed by Accounting Standards Codification (“ASC”) 815. Accordingly, the Company does not account for its derivative instruments as cash flow hedges for financial reporting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in net gains (losses) on commodity derivative contracts in the Consolidated Statements of Operations.

Fair Value of Financial Instruments

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the carrying value. The carrying value of those financial instruments that are classified as current, except for derivative instruments, approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

Share-Based Payments

Options granted are valued at the date of grant and expense is recognized over the vesting period. The Company currently utilizes a standard option pricing model (Black-Scholes) to measure the fair value of stock options granted to employees and directors. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such restricted stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2016, 2017 and 2018, stock-based compensation was approximately $3.2 million, $3.2 million and $2.4 million, respectively.

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements. Each year, the Company reviews, and to the extent necessary, revises its asset retirement obligation estimates.

The following table (in thousands) summarizes changes in the Company's future site restoration obligations during the two years ended December 31:

	2017	2018
Beginning future site restoration obligation	$8,623	$8,775
New wells placed on production and other	1,088	612
Deletions related to property disposals and plugging costs	(1,551)	(2,270)
Accretion expense and other	451	516
Revisions and other	164	(141)
Ending future site restoration obligation	$8,775	$7,492

Revenue Recognition and Major Purchasers

The Company recognizes oil and gas revenue from its interest in producing wells as oil and gas is sold from those wells, net of royalties. The Company recognizes oil and gas revenues from its interests in producing wells when control has transferred to the purchaser and to the extent the selling price is reasonably determinable. The Company had no material gas imbalances at December 31, 2017 and 2018.

During 2016, two purchasers accounted for 71% of oil and gas revenues. During 2017 three purchasers accounted for 69% of oil and gas revenues. During 2018, two purchasers accounted for 57% of oil and gas revenues.

Deferred Financing Fees

Deferred financing fees are being amortized on the effective yield basis over the term of the related debt.

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to be in effect with respect to taxable income in the years in which those temporary differences are expected to be recovered or settled. Uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, we have established a valuation allowance of $67.3 million for deferred tax assets at December 31, 2018.

On December 22, 2017, the President of the United States signed Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”). The Tax Act, among other things, (i) permanently reduces the U.S. federal corporate income tax rate from 35% to 21%, (ii) repeals the corporate alternative minimum tax, (iii) imposes new limitations on the utilization of net operating losses (iv) limits deductibility of interest expense and (v) changes the cost recovery rules. Under U.S. GAAP, the effects of new legislation are recognized upon enactment, which, for federal legislation, is the date the President signs a bill into law. Accordingly, recognition of the tax effects of the Tax Act was required in the interim and annual periods that included December 22, 2017. In December 2017, the SEC issued Staff Accounting Bulletin No. 118 “Income Tax Accounting Implications of the Tax Cuts and Jobs Act” (“SAB 118”) which allows a company up to one year to finalize and record the tax effects of the Tax Act and clarifies certain aspects of Accounting Standards Codification 740, “Income Taxes” (“ASC 740”) and provides a three-step process for applying ASC 740. The tax effect of the Tax Act, did not have a material impact to the Company's deferred tax position.

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Accounting for Uncertainty in Income Taxes

Evaluation of a tax position is a two-step process. The first step is to determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation based on the technical merits of that position. The second step is to measure a tax position that meets the more-likely-than-not threshold to determine the amount of benefit to be recognized in the financial statements. A tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent period in which the threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not criteria should be de-recognized in the first subsequent reporting period in which the threshold is no longer met. Penalties and interest are classified as income tax expense. The Company had no uncertain income tax positions as of December 31, 2018.

New Accounting Standards and Disclosures

In February 2016, the FASB issued new guidance in ASC 842, *Leases* ("ASC 842"), which will supersede the current guidance in ASC 840, *Leases* ("ASC 840"). The core principle of the new guidance is that a lessee should recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for leases currently classified as operating leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. In January 2018, the FASB issued new guidance in ASC 842 to provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840.

In July 2018, the FASB issued new guidance in ASC 842 to provide entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with ASC 840. An entity that elects this transition method must provide the required ASC 840 disclosures for all periods that continue to be reported in accordance with ASC 840.

The amendments in these ASUs are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption was permitted. The Company expects to adopt ASU 2016-02 using a modified retrospective method in the first quarter of 2019 (that is, the initial period of adoption) through a cumulative-effect adjustment to the opening balance of retained earnings. At transition, the Company plans to apply the package of practical expedients provided in ASC 842 that allow companies, among other things, to not reassess contracts that commenced prior to adoption.

The Company has a team, including third-party consultants, to implement the standard and is implementing a software solution that will be used to track and account for its leases under ASC 842 on an ongoing basis. The primary effect on the Company's consolidated financial statements will be to record a right-of-use (ROU) asset and lease liability on the balance sheet for all leases with terms at commencement that are greater than twelve months. Leases will be classified as either finance or operating, with that classification affecting the pattern of expense recognition in the income statement. We anticipate the impact of recording leases as a result of the adoption of this standard to be less than $2.0 million.

The Company enters into certain lease agreements in support of its operations for assets such as compressors, a drilling rig, employee housing and office equipment. As of December 31, 2018, the Company does not anticipate that the adoption and implementation of ASC 842 will result in material changes in assets and liabilities on the consolidated balance sheet in 2019, and will not result in a material impact to the consolidated statement of operations.

The Company has made certain accounting policy decisions including that it plans on adopting the short-term lease recognition exemption, account for certain asset classes and has established a balance sheet recognition capitalization threshold. The Company also expects for certain lessee asset classes to elect the practical expedient to not separate lease and non-lease components. For these asset classes, the agreements will be accounted for as a single component.

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2. Impact of ASC 606 Adoption

On January 1, 2018, the Company adopted ASU No. 2014-09, "*Revenue from Contracts with Customers*" ("ASU 2014-09") using the modified retrospective method of transition. Under this method of transition, the Company applied ASU 2014-09 to all new contracts entered into on and after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue attributable to a contract had not been recognized under legacy revenue guidance.

ASU 2014-09 superseded nearly all existing revenue recognition guidance under U.S. GAAP and includes a five step process to recognize revenue when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

For the year ended December 31, 2018, there was no impact to the Company's reported revenues, operating costs and expenses or net income as a result of adopting ASU 2014-09, as compared to legacy revenue guidance. In addition, no cumulative catch-up adjustment to accumulated deficit was required on January 1, 2018 as a result of adopting ASU 2014-09.

3. Revenue from Contracts with Customers

Revenue Recognition

Sales of oil, gas and NGL are recognized at the point in time when control of the product is transferred to the customer and collectability is reasonably assured. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, physical location, quality of the oil or gas, and prevailing supply and demand conditions. As a result, the price of the oil, gas and NGL fluctuates to remain competitive with other available oil, gas and NGL supplies in the market. The Company believes that the pricing provisions of our oil, gas and NGL contracts are customary in the industry.

Oil sales

The Company's oil sales contracts are generally structured such that it sells its oil production to a purchaser at a contractually specified delivery point at or near the wellhead. The crude oil production is priced on the delivery date based upon prevailing index prices less certain deductions related to oil quality, physical location and transportation costs incurred by the purchaser subsequent to delivery. The Company recognizes revenue when control transfers to the purchaser upon delivery at or near the wellhead at the net price received from the purchaser. Payment terms as customarily and normally paid on the twentieth day of the month following production.

Gas and NGL Sales

Under the Company's gas processing contracts, it delivers wet gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity’s system. There are no performance obligations related to these contracts. The midstream processing entity processes the gas and remits proceeds to the Company based upon either (i) the resulting sales price of NGL and residue gas received by the midstream processing entity from third party customers or (ii) the prevailing index prices for NGL and residue gas in the month of delivery to the midstream processing entity. Gathering, processing, transportation and other expenses incurred by the midstream processing entity are typically deducted from the proceeds that the Company receives.

In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. With respect to the Company's gas purchase contracts, the Company has concluded that it is the agent, and thus, the midstream processing entity is its customer. Accordingly, the Company recognizes revenue upon delivery to the midstream processing entity based on the net amount of the proceeds received from the midstream processing entity.

Imbalances

The Company had no material gas imbalances at December 31, 2017 and 2018.

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Disaggregation of Revenue

The Company is focused on the development of oil and natural gas properties primarily located in the following three operating regions in the United States: (i) the Permian/Delaware Basin, (ii) Rocky Mountain and (iii) South Texas. Revenue attributable to each of those regions is disaggregated in the table below.

	Years Ended December 31,								
	2016			2017			2018		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	(In thousands)								
Operating Region									
Permian/Delaware Basin	$3,551	$1,672	$664	$17,722	$3,028	$1,840	$47,175	$2,698	$2,884
Rocky Mountain	$40,048	$1,070	$793	$49,670	$2,694	$3,774	$77,664	$3,913	$5,253
South Texas	$7,366	$1,236	$93	$6,192	$1,176	$93	$8,065	$1,243	$135

Significant Judgments

Principal versus agent

The Company engages in various types of transactions in which midstream entities process the Company's gas and subsequently market resulting NGL and residue gas to third-party customers on behalf of the Company, such as the Company's percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC Topic 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606-10-50-14(a) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under the Company's product sales contracts, the Company is entitled to payment from purchasers once its performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional. The Company records invoiced amounts as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheet.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheets. In this scenario, payment is also unconditional, as the Company has satisfied its performance obligations through delivery of the relevant product. As a result, the Company has concluded that its product sales do not give rise to contract assets or liabilities under ASU 2014-09. At December 31, 2017 and December 31, 2018, our receivables from contracts with customers were $17.8 million and $22.0 million, respectively.

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Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the midstream purchaser and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil are also estimated.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the year ended December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

4. Acquisitions and Divestitures of Properties

During the year ended December 31, 2018, through multiple transactions, the Company acquired approximately 2,721 net mineral acres of additional leasehold and working interests in its Permian Basin region for an aggregate purchase price of $40.4 million, net of post-closing adjustments. These acquisitions were accounted for as asset acquisitions. Acquisition cost of approximately $21,000 were capitalized in connection with these transactions.

During 2018, the Company divested of various non-core properties for net proceeds of approximately $3.3 million.

5. Long-Term Debt

The following is a description of the Company’s debt as of December 31, 2017 and 2018, respectively:

	2017	**2018**
	(In thousands)	

Senior secured credit facility	$84,000	$180,000
Real estate lien note	3,616	3,358
	87,616	183,358
Less current maturities	(262)	(267)
Total	$87,354	$183,091

Maturities of long-term debt are as follows:

Years ending December 31,	(In thousands)
2019	$267
2020	280
2021	180,295
2022	310
2023	2,206
Thereafter	-
Total	$183,358

Credit Facility

The Company has a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of December 31, 2018, $180.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At December 31, 2018, the Company had a borrowing base of $200.0 million. The borrowing base is determined semi-annually by the lenders based upon the Company's reserve reports, one of which must be prepared by its independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of the Company's proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and the Company is able to request one redetermination during any six-month period between scheduled redeterminations. Outstanding borrowings in excess of the borrowing base must be repaid immediately or the Company must pledge additional oil and gas properties or other assets as collateral. The Company does not currently have any substantial unpledged assets and it may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause the Company to fail to be in compliance with the financial covenants described below. The Company's borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of its then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. The Company's borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (i) 1.5%-2.5%, depending on the utilization of the borrowing base, or (ii) if we elect, LIBOR plus, in each case, 2.5%-3.5% depending on the utilization of the borrowing base. At December 31, 2018, the interest rate on the credit facility was approximately 6.0% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is May 16, 2021. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the credit facility and is able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of the Company's subsidiaries has guaranteed the obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of the Company's proven reserves. The Company has also granted its lenders a security interest in our headquarters building.

Under the credit facility, the Company is subject to customary covenants, including certain financial covenants and reporting requirements. The Company is required to maintain a current ratio, as defined in the credit facility, as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00. The Company is also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 3.50 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is defined as the sum of consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts plus expenses incurred in connection with the negotiation, execution, delivery and performance of the credit facility plus expenses incurred in connection with any acquisition permitted under the credit facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses minus all non-cash items of income which were included in determining consolidated net loss, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the headquarters building and obligations with respect to surety bonds and derivative contracts.

At December 31, 2018, we were in compliance with the interest coverage ratio and the total debt to EBITDAX ratio and received a waiver with respect to our non-compliance with the current ratio. As of December 31, 2018, the interest coverage ratio was 11.94 to 1.00, the total debt to EBITDAX ratio was 2.14 to 1.00, and our current ratio was 0.96 to 1.00. We received a waiver for the non-compliance with the current ratio which related only to compliance at December 31, 2018.

The credit facility contains a number of other covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an “arm’s length” basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The credit facility also contains certain additional covenants including:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and
- If the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities. As of December 31, 2018, we were in compliance with, or have obtained a waiver for, all of the terms of our credit facility.

Real Estate Lien Note

The Company has a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note was modified on June 20, 2018 to a fixed rate of 4.9% and is payable in monthly installments of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2017 and 2018, $3.6 million and $3.4 million, respectively, were outstanding on the note.

6. Property and Equipment

The major components of property and equipment, at cost, are as follows:

	Estimated Useful life Years	**December 31, 2017**	**2018**
		(In thousands)	
Oil and gas properties	(1)	$923,237	$1,091,905
Equipment and other	3-39	15,648	15,369
Drilling rig	15	23,488	24,084
		962,373	1,131,358
Accumulated depreciation, depletion, amortization and impairment		(724,606)	(768,140)
Net Property and Equipment		$237,767	$363,218

(1) Oil and gas properties are amortized utilizing units of production method.

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7. Stock-Based Compensation and Option Plans

The Company's Amended and Restated 2005 Employee Long-Term Equity Incentive Plan reserves 12.6 million shares of Abraxas common stock, subject to adjustment following certain events. Awards may be in options or shares of restricted stock. Options have a term not to exceed 10 years. Options issued under this plan vest according to a vesting schedule as determined by the compensation committee of the Company's board of directors. Vesting may occur upon (1) the attainment of one or more performance goals or targets established by the committee, (2) the optionee's continued employment or service for a specified period of time, (3) the occurrence of any event or the satisfaction of any other condition specified by the committee, or (4) a combination of any of the foregoing.

Stock Options

The Company utilizes a standard option pricing model (Black-Scholes) to measure the fair value of stock options granted to employees and directors. The fair value for these options was estimated at the date of grant using the following weighted average assumptions for 2016, 2017 and 2018:

	2016	**2017**	**2018**
Weighted average value per option granted during the period	$0.68	$1.81	$1.87
Assumptions:			
Forfeiture rate (1)	4.2 %	2.0 %	1.7 %
Expected dividend yield (2)	0.0 %	0.0 %	0.0 %
Volatility (3)	71.1 %	67.6%	66.5%
Risk free interest rate (4)	1.7 %	2.2 %	2.9 %
Expected life (years) (5)	7.0	6.9	7.3
Fair value of options granted (in thousands)	$2,307	$574	$841

(1) The estimated future forfeiture rate is based on the Company's historical forfeiture rate on similar grants of stock options.

(2) The dividend yield is based on the fact the Company does not pay any dividends.

(3) The volatility is based on the historical volatility of our stock for a period approximating the expected life.

(4) The risk-free interest rate is based on the observed U.S. Treasury yield curve in effect at the time the options were granted for a period approximating the expected life of the option.

(5) The expected life was derived based on a weighting between (a) the Company's historical exercise and forfeiture activity and (b) the average midpoint between vesting and the contractual term.

The Company grants options to its officers, directors, and other employees under various stock option and incentive plans.

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The following table is a summary of the Company’s stock option activity for the three years ended December 31:

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Intrinsic value per share
Options outstanding December 31, 2015	6,808	$ 2.89		
Granted	2,265	1.02		
Exercised	(83)	1.40		
Forfeited/Expired	(836)	2.84		
Options outstanding December 31, 2016	8,154	$ 2.39		
Granted	317	1.81		
Exercised	(5)	0.97		
Forfeited/Expired	(149)	3.58		
Options outstanding December 31, 2017	8,317	$ 2.35		
Granted	300	2.80		
Exercised	(379)	1.71		
Forfeited/Expired	(689)	2.70		
Options outstanding December 31, 2018	7,549	$ 2.37	4.9	$ 1.68
Exercisable at end of year	6,479	$ 2.50	4.5	$ 1.78

Other information pertaining to the Company’s stock option activity for the three years ended December 31:

	2016	2017	2018
Weighted average grant date fair value of stock options granted (per share)	$0.68	$1.81	$1.87
Total fair value of options vested (000's)	$2,776	$2,795	$2,054
Total intrinsic value of options exercised (000's)	$39	$5	$395

As of December 31, 2018, the total compensation cost related to non-vested awards not yet recognized was approximately $0.5 million, which will be recognized in 2019 through 2021. For the years ended December 31, 2016, 2017 and 2018, we recognized $2.0 million, $1.8 million and $1.4 million, respectively, in stock-based compensation expense relating to options.

The following table represents the range of stock option prices and the weighted average remaining life of outstanding options as of December 31, 2018:

	Outstanding Options			Exercisable		
		Weighted	Weighted		Weighted	Weighted

Range of stock option prices	Number Outstanding	average remaining life	average exercise price	Number Outstanding	average remaining life	average exercise price
0.97 - 1.99	3,270,117	4.9	$ 1.26	2,490,367	4.2	$ 1.32
2.00 - 2.99	1,422,975	4.4	$ 2.44	1,319,725	4.0	$ 2.43
3.00 - 3.99	2,212,606	5.4	$ 3.29	2,025,106	5.3	$ 3.30
4.00 - 4.99	544,750	4.2	$ 4.54	544,750	4.2	$ 4.54
5.00 - 5.99	98,000	5.4	$ 5.38	98,000	5.4	$ 5.38
6.00 - 6.28	1,000	5.5	$ 6.28	1,000	5.5	$ 6.28
	7,549,448	4.9	$ 2.37	6,478,948	4.5	$ 2.50

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date. Compensation expense is recorded over the applicable restricted stock vesting periods. As of December 31, 2018, the total compensation cost related to non-vested awards not yet recognized was approximately $1.3 million, which will be recognized from 2019 through 2021. For the years ended December 31, 2016, 2017 and 2018, we recognized $1.2 million, $1.4 million and $0.7 million, respectively, in stock-based compensation expense related to restricted stock awards.

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The following table is a summary of the Company's restricted stock activity for the three years ended December 31, 2018:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2015	1,643,284	$ 3.44
Granted	-	-
Vested/Released	(52,017)	2.40
Forfeited	(98,802)	3.63
Unvested December 31, 2016	1,492,465	$ 3.47
Granted	44,000	1.75
Vested/Released	(56,340)	3.14
Forfeited	(750)	2.63
Unvested December 31, 2017	1,479,375	$ 3.43
Granted	861,113	2.17
Vested/Released	(1,326,250)	3.43
Forfeited	(187,557)	3.22
Unvested December 31, 2018	826,681	$ 2.15

Performance Based Restricted Stock Awards

Effective on April 1, 2018, the Company issued performance-based shares of restricted stock to certain officers and employees under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. The shares will vest in 2021 upon the achievement of performance goals based on the Company's Total Shareholder Return ("TSR") as compared to a peer group of companies. The number of shares which would vest depends upon the rank of the Company's TSR as compared to the peer group at the end of the three-year vesting period, and can range from zero percent of the initial grant up to 200% of the initial grant.

The table below provides a summary of Performance Based Restricted Stock as of the date indicated (shares in thousands):

	Number of Shares	Weighted average grant

		date fair value
Unvested December 31, 2017	-	$ -
Granted	464	2.37
Vested/Released	-	-
Forfeited	(59)	2.37
Unvested December 31, 2018	405	$ 2.37

Compensation expense associated with the performance based restricted stock is based on the grant date fair value of a single share as determined using a 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 performance based restricted stock awards with shares of the Company's common stock, the awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the awards.

As of December 31, 2018, the total compensation cost related to non-vested awards not yet recognized was approximately $0.7 million, which will be recognized from 2019 through 2021. For the year ended December 31, 2018, we recognized $0.2 million, in stock-based compensation expense related to performance based restricted stock awards.

Director Stock Awards

The 2005 Directors Plan (as amended and restated) reserves 2.9 million shares of Abraxas common stock, subject to adjustment following certain events. The 2005 Directors Plan provides that each year, at the first regular meeting of the board of directors immediately following Abraxas' annual stockholder's meeting, each non-employee director shall be granted or issued awards of 25,000 shares of Abraxas common stock, for participation in board and committee meetings during the previous calendar year. The maximum annual award for any one person is 100,000 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise price shall be no less than 100% of the fair market value on the date of the award while the option terms and vesting schedules are at the discretion of the committee.

At December 31, 2018, the Company had approximately 10.3 million shares reserved for future issuance for conversion of its stock options, and incentive plans for the Company's directors, employees and consultants.

Common Stock Issuance

In May 2016, we completed a stock offering of 28.8 million shares of common stock for net proceeds of approximately $27.1 million and in January 2017, we completed an offering of 28.8 million shares of common stock for net proceeds of approximately $65.2 million.

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8. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

	As of December 31,		
	2016	**2017**	**2018**
	(In thousands)		
Deferred tax liabilities:			
Hedge contracts	$-	$-	$3,167
Assets held for sale	3,390	-	-
Other	4,431	2,834	2,977
Total deferred tax liabilities	7,821	2,834	6,144
Deferred tax assets:			
Oil and gas properties	48,436	20,011	4,310
Capital loss carryforwards	7,361	3,015	3,980
Depletion carryforward	5,216	3,174	3,098
U.S. net operating loss carryforward	80,670	53,545	61,309
Alternative minimum tax credit	757	757	757
Hedge contracts	3,135	2,777	-
Total deferred tax assets	145,575	83,279	73,454
Valuation allowance for deferred tax assets	(137,754)	(80,445)	(67,310)
Net deferred tax assets	7,821	2,834	6,144
Net deferred tax	$-	$-	$-

Significant components of the provision (benefit) for income taxes are as follows:

	Years ended December 31,		
	2016	**2017**	**2018**
	(In thousands)		
Current:			
Federal	$—	$ —	$ —
State	—	—	—
	$—	$ —	$ —
Deferred:			
Federal	$—	$ —	$ —
	$—	$ —	$ —

At December 31, 2018, the Company had, $245.2 million of pre 2018 NOLs for U.S. tax purposes and $46.8 million of 2018 NOLs for U.S. tax purposes. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018, can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

The use of our NOLs will be limited if there is an "ownership change" in our common stock, generally a cumulative ownership change exceeding 50% during a three year period, as determined under Section 382 of the Internal Revenue Code. As of December 31, 2018, we have not had an ownership change as defined by Section 382. Given historical losses, uncertainties exist as to the future utilization of the NOL carryforwards, therefore, the Company has established a valuation allowance of $137.8 million at December 31, 2016, $80.4 million at December 31, 2017 and $67.3 million at December 31, 2018.

The reconciliation of income tax computed at the U.S. federal statutory tax rates to income tax expense is:

	Years Ended December 31,		
	2016	**2017**	**2018**
	(In thousands)		
Tax (expense) benefit at U.S. Statutory rates	$33,732	$(5,602)	$(12,142)
(Increase) decrease in deferred tax asset valuation allowance	(34,072)	57,309	13,135
Permanent differences	(1,133)	(1,134)	(500)
Return to provision estimated revision	1,473	2,494	(470)
Change in deferred tax rate	-	(53,125)	-
Other	-	58	(23)
	$-	$-	$-

As of December 31, 2016, 2017 and 2018, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2013 through 2018 remain open to examination by the tax jurisdictions to which the Company is subject.

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New tax legislation, commonly referred to as the Tax Cuts and Jobs Act (H.R. 1), was enacted on December 22, 2017. ASC740, *Accounting for Income Taxes*, requires companies to recognize the effect of tax law changes in the period of enactment even though the effective date for most provisions is for tax years beginning after December 31, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance, the reduction in the U.S. corporate income tax rate to 21% did not materially affect the Company's financial statements. Significant provisions that will impact income taxes in future years include: the repeal of the corporate Alternative Minimum Tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

9. Commitments and Contingencies

Operating Leases

The Company leases office space in Dickinson, North Dakota, Lusk, Wyoming and Denver, Colorado. During 2016, 2017 and 2018, rent expense incurred for the Dickinson, North Dakota office was $27,165, $27,840, and $23,200, respectively. The lease expired on October 31, 2018 and was not renewed. Rent expense incurred for the Lusk, Wyoming office for 2016 and 2017 was $9,000 for each year. The lease expired on December 31, 2017 and was not renewed. Rent expense for the Denver Colorado office for 2016 and 2017 was $15,601 and $13,837, respectively. The lease expired on December 31, 2017 and was not renewed.

Litigation and Contingencies

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2018, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

10. Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Years ended December 31,		
	2016	**2017**	**2018**
	(in thousands, except per share data)		
Numerator:			
Net income (loss)	$(96,378)	$16,006	$57,821
Denominator for basic earnings per share - weighted-average common shares outstanding	122,132	161,141	165,635
Effect of dilutive securities: Stock options, restricted shares and performance based shares	-	1,703	2,054
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	122,132	162,844	167,689
Net (loss) income per common share - basic	$(0.79)	$0.10	$0.35
Net (loss) income per common share - diluted	$(0.79)	$0.10	$0.34

Basic earnings per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities. For the year ended December 31, 2016, 1,635 of potential shares relating to stock options and unvested restricted shares were excluded from the calculation of diluted income (loss) per share since their inclusion would have been anti-dilutive due to the loss incurred in the period. For the year December 31, 2017 and 2018, 5,018 and 4,007 of potential shares relating to stock options and unvested restricted shares were excluded from the calculation of diluted income (loss) per share since their inclusion would have been anti-dilutive due to the options being underwater, respectively

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11. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2017 and 2018 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2017				
Net revenue	$18,802	$13,152	$24,722	$29,588
Operating income	$4,953	$1,260	$5,654	$9,470
Net income (loss)	$13,690	$7,195	$(770)	$(4,109)
Net income (loss) per common share - basic	$0.09	$0.04	$-	$(0.02)
Net income (loss) per common share - diluted	$0.09	$0.04	$-	$(0.02)
Year Ended December 31, 2018				
Net revenue	$40,630	$30,916	$41,625	$35,996
Operating income	$20,090	$10,931	$17,735	$8,722
Net income (loss)	$10,779	$(10,554)	$1,777	$55,819
Net income (loss) per common share - basic	$0.07	$(0.06)	$0.01	$0.34
Net income (loss) per common share - diluted	$0.06	$(0.06)	$0.01	$0.33

12. Benefit Plans

The Company has a defined contribution plan (401(k) plan) covering all eligible employees. In 2016, 2017 and 2018, in accordance with the safe harbor provisions of the plan, the Company contributed $256,309, $330,415 and $331,957, respectively, to the plan. The Company adopted the safe harbor provisions for its 401(k) plan which requires it to contribute a fixed match to each participating employee's contribution to the plan. The fixed match is set at the rate of dollar for dollar on the first 1% of eligible pay contributed, then 50 cents on the dollar for each additional percentage point of eligible pay contributed, up to 5%. Each employee's eligible pay with respect to calculating the fixed match is limited by IRS regulations. In addition, the Board of Directors, at its sole discretion, may authorize the Company to make additional contributions to each participating employee's plan. The employee contribution limit for 2016 and 2017 was $18,000 for employees under the age of 50 and $24,000 for employees 50 years of age or older. The employee contribution limit was increased in 2018 to $18,500 for employees under the age of 50 and $24,500 for employees 50 years of age and older.

13. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Our derivative contracts have not been designated for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. There are no netting agreements relating to these derivative contracts and there is no policy to offset.

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The following table sets forth the summary position of our derivative contracts as of December 31, 2018

	Oil - WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
January - December 2019	2,941	$56.20
January - December 2020	2,204	$54.35
January - December 2021	1,815	$60.32
Basis Swaps		
January - December 2019	4,000	$2.98
January - December 2020	4,000	$2.98

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

Fair Value Derivative Contracts as of December 31, 2017

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$-	Derivatives - current	$10,837
Commodity price derivatives	Derivatives - long-term	-	Derivatives - long-term	2,387
		$-		$13,224

Fair Value Derivative Contracts as of December 31, 2018

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$9,602	Derivatives - current	$616
Commodity price derivatives	Derivatives - long-term	10,527	Derivatives - long-term	4,434
		$20,129		$5,050

Gains and losses from derivative activities are reflected as "(Gain) loss on derivative contracts" in the accompanying Consolidated Statements of Operations. The net estimated value of our commodity derivative contracts was an asset of approximately $15.1 million as of December 31, 2018. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year-ended December 31, 2018, we recognized a gain of $8.1 million, consisting of a loss of $19.0 million on closed contracts and a gain of $27.1 million on the mark to market valuation on open contracts. For the year ended December 31, 2017, we incurred a loss on our derivative contracts of approximately $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million on the mark to market valuation of open contracts.

14. Financial Instruments

There is a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

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A financial instrument's categorization within the valuation hierarchy is based upon 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 in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2017 and 2018, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2017
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
Total Assets	$ -	$ -	$ -	$ -
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 13,208	$ -	$ 13,208
NYMEX basis differential swap	-	-	16	16
Total Liabilities	$ -	$ 13,208	$ 16	$ 13,224

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2018
Assets:				
NYMEX fixed price derivative contracts	$ -	$ 18,172	$ -	$ 18,172
NYMEX basis differential swap	-	-	1,957	1,957
Total Assets	$ -	$ 18,172	$ 1,957	$ 20,129
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
NYMEX basis differential swap	-	-	5,050	5,050
Total Liabilities	$ -	$ -	$ 5,050	$ 5,050

The Company’s derivative contracts at December 31, 2018 consisted of NYMEX-based fixed price commodity swaps and basis differential swaps. The NYMEX-based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, we enter the various inputs into a model and compare our results to the third party for reasonableness. The fair value of the basis swaps are based on inputs that are not as observable as the fixed price swaps. In addition to the actively quoted market price, variables such as time value, volatility and other unobservable inputs are used. Accordingly, these instruments have been classified as Level 3.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the year ended December 31, 2018.

	(In thousands)	
Unobservable inputs at January 1, 2018	$ (16	)
Changes in market value	$ (3,093	)
Settlements during the period	$ 16	
Unobservable inputs at December 31, 2018	$ (3,093	)

There were no transfers from level 3 in 2018.

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Nonrecurring Fair Value Measurements

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. As it relates to the Company, ASC 820-10 applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligation is presented in Note 1.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

15. Subsequent Events

In March 2019, the Company entered into the following derivative contracts:

	Oil - WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
July - December 2019	1,156	$58.50
January - December 2020	819	$57.65

January - December 2021	236	$55.70

16. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying tables (in thousands) presents information concerning the Company's oil and gas producing activities "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows as of December 31:

	Years Ended December 31,	
	2017	**2018**
Proved oil and gas properties	$923,237	$1,091,905
Unproved properties	-	-
Total	923,237	1,091,905
Accumulated depreciation, depletion, amortization and impairment	(706,537)	(748,773)
Net capitalized costs	$216,700	$343,132

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Cost incurred in oil and gas property acquisition and development activities were as follows for the years ended December 31 (in thousands):

	2016	2017	2018
Development costs	$18,262	$94,478	$131,271
Exploration costs	12,529	8,509	-
Property acquisition costs	-	31,409	41,465
	$30,791	$134,396	$172,736

Results of operations from oil and gas producing activities were as follows for the years ended December 31:

	2016	2017	2018
Revenues	$56,493	$86,189	$149,030
Production costs	(23,659)	(22,425)	(36,323)
Depreciation, depletion and amortization	(22,803)	(25,676)	(42,237)
Proved property impairment	(67,626)	-	-
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$(57,595)	$38,088	$70,470
Depletion rate per barrel of oil equivalent	$10.08	$9.52	$11.80

Estimated Quantities of Proved Oil and Gas Reserves

Reserve estimates are inherently imprecise and estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been predominately prepared by independent petroleum reserve engineers. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company’s proved reserves are located in the continental United States.

Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, the unweighted average prior 12-month first-day-of-the-month commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows for the periods presented.

The following set forth changes in estimated net proved reserves for the years ended December 31, 2016, 2017 and 2018.

	Oil (MBbl)	**NGL (MBbl)**	**Gas (MMcf)**	**Oil Equivalents (Mboe)**
Change in Proved Reserves				
Balance at December 31, 2015	24,131	6,556	75,027	43,190
Revisions of previous estimates	1,379	2,300	(1,537)	3,424
Extensions and discoveries	1,183	157	1,179	1,537
Sales of minerals in place	(1,112)	(6)	(680)	(1,232)
Production	(1,372)	(363)	(3,160)	(2,262)
Balance at December 31, 2016	24,209	8,644	70,829	44,657
Revisions of previous estimates	259	1,269	19,311	4,747
Extensions and discoveries	14,533	2,813	14,534	19,768
Purchases of minerals in place	8	14	1,001	189
Sales of minerals in place	(364)	(289)	(3,958)	(1,312)
Production	(1,574)	(476)	(3,889)	(2,698)
Balance at December 31, 2017	37,071	11,975	97,828	65,351
Revisions of previous estimates	(4,206)	(1,927)	(2,618)	(6,570)
Extensions and discoveries	11,270	1,797	11,475	14,979
Purchases of minerals in place	688	-	1,137	877
Sales of minerals in place	(278)	(1,303)	(13,491)	(3,829)
Production	(2,308)	(508)	(4,587)	(3,580)
Balance at December 31, 2018	42,237	10,034	89,744	67,228

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The following is a summary of the changes to the Company’s proved reserves that occurred during 2018:

Revisions to prior estimates:

There was a decrease of 45 MBoe of net reserves attributable to changes in projections for the Company’s producing wells based on actual performance during 2018. The Company also converted thirteen proved undeveloped Three Fork 2nd bench locations in McKenzie County, North Dakota, to probable undeveloped reserves during 2018, accounting for 6,525 MBoe of net reserves. These locations are no longer included in the Company’s five-year development plan.

Extensions, discoveries and other additions:

The Company added nineteen new proved undeveloped operated locations accounting for 8,130 MBoe of net reserves along with two proved undeveloped non-operated locations accounting for 838 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing wells or producing wells operated by others. The Company also converted two probable undeveloped locations to producing reserves accounting for 1,523 MBoe of net reserves. The Company also converted five probable undeveloped locations to proved undeveloped reserves accounting for 2,670 MBoe of net reserves. In the Bakken/Three Forks system in McKenzie County, North Dakota, during 2018 the Company added three new proved undeveloped locations attributable to unit line well configurations accounting for 1,692 MBoe of net reserves. The Company also added six new non-operated proved non-producing locations accounting for 126 MBoe of net reserves.

Purchases:

In the Wolfcamp/3rd Bone Spring system in Ward, County, Texas, during 2018 the Company acquired four new producing wells accounting for 877 MBoe of net producing reserves.

Sales:

The Company sold substantially all its holdings in the Ira Area accounting for 203 MBoe of net proved reserves. The Company also sold one producing and two proved undeveloped Delaware locations in Ward County, Texas, accounting for 3,558 MBoe of net reserves. Other miscellaneous asset sales during the year accounted for 68 MBoe of net reserves.

Production:

The Company produced 3,580 MBoe of net reserves during 2018.

The following is a summary of the changes to the Company's proved reserves that occurred during 2017:

Revisions to prior estimates:

There was an increase of 621 MBoe of net reserves attributable to changes in projections for the Company's producing wells based on actual performance during 2017. Most of this increase was attributable to the Company's Wolfcamp producing wells in Ward County, Texas. There was also an increase of 1,951 net MBoe attributable to increases in projections for the Company's Wolfcamp PUDs in Ward County. These increases were based on the over-performance of the Company's existing Wolfcamp producing wells as mentioned above. There was also an increase in this category of 2,698 MBoe attributable to increased economic life calculations at the higher commodity pricing experienced during 2017. There were also seven miscellaneous cases in this category that were removed from the report due to the fact that the Company no longer intends to develop them within the five-year allowance. These cases accounted for 523 MBoe of net reserves.

Extensions, discoveries and other additions:

The Company added three new Wolfcamp producing wells in Ward, County, Texas accounting for 1,229 MBoe of net producing reserves. The Company also converted three probable undeveloped Wolfcamp A locations in Ward County, TX, to proved producing reserves during 2017 accounting for 2,028 MBoe of net reserves. The Company also added 27 proved undeveloped Wolfcamp A locations, four Third Bone Spring locations, and two Wolfcamp B locations in Ward County, Texas, accounting for 11,928 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing wells or producing wells operated by others. The Company also converted ten probable undeveloped Wolfcamp A locations in Ward County, Texas, to proved undeveloped reserves during 2017 accounting for 4,343 MBoe of net reserves. The Company also developed a new Eagle Ford well in Atascosa County, Texas, accounting for 240 MBoe of net reserves.

Purchases:

The company purchased wells and acquired additional interest in existing wells which added 189 MBoe of net reserves.

Sales:

The Company sold substantially all of its holdings in the Powder River Basin of Wyoming during 2017. These sales accounted for the decrease of 1,312 MBoe of net proved reserves.

Production:

The Company produced 2,698 MBoe of net reserves during 2017.

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The following is a summary of the changes to the Company's proved reserves that occurred during 2016:

Revisions to prior estimates:

An increase of 5,005 MBoe of reserves was attributable to the Company's Bakken and Three Forks proved undeveloped locations in McKenzie County, North Dakota, due to continuing improvement in its producing well production results. Well results improved as a result of the application of optimized completion methods. Similarly, reserves for the Company's Bakken and Three Forks producing wells increased by 1,360 MBoe of net producing reserves due to improved performance. Projections for the Hedgehog State 16-2H producing well and its two related proved undeveloped locations in the Porcupine Field, Campbell County, Wyoming, decreased by 670 MBoe of net reserves due to the under-performance of the Hedgehog State 16-2H. There was also a reduction in this category of 2,271 MBoe attributable to shortened economic life calculations at the lower commodity pricing.

Extensions, discoveries and other additions:

The Company added the Caprito 99 302H as a new Wolfcamp producing well in Ward County, Texas, accounting for 449 MBoe of net producing reserves. It also added five new proved undeveloped Wolfcamp locations offsetting this new producer accounting for 805 MBoe of net undeveloped reserves. The Company also developed a new Austin Chalk producer in Atascosa County, Texas, which accounted for 265 MBoe of net producing reserves. Further, the Company added eight new proved undeveloped Bakken/Three Forks locations on non-operated units in McKenzie County, North Dakota, accounting for 18 MBoe of net undeveloped reserves. These locations were added in response to operator well proposals.

Sales:

The Company sold all its holdings in the Portilla Field in San Patricio County, Texas, and in the Brooks Draw Field in Converse County, Wyoming, during 2016. These sales accounted for 1,232 MBoe of net proved reserves.

Production:

The Company produced 2,262 MBoe of net reserves during 2016.

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The following table presents the Company's estimate of its net proved developed and undeveloped oil and gas reserves as of December 31, 2016, 2017 and 2018:

	Total			
	OIl (MBbl)	**NGL (MBbl)**	**Gas (MMcf)**	**Oil Equilavents (Mboe)**
Proved Developed Reserves:				
December 31, 2016	7,818	2,568	27,792	15,018
December 31, 2017	10,820	3,794	39,974	21,720
December 31, 2018	13,586	3,804	43,271	24,602
Proved Undeveloped Reserves:				
December 31, 2016	16,391	6,076	43,037	29,639
December 31, 2017	25,808	8,181	57,854	43,631
December 31, 2018	28,651	6,230	46,473	42,626

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company’s proved oil and gas reserves have been estimated by the Company with the assistance of an independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2016, and 2017 and LaRoche Petroleum Consultants as of December 31, 2018, assisted by the engineering and operations departments of the Company.

The following information has been prepared in accordance with SEC rules and accounting standards based on the 12-month first-day-of-the-month unweighted average prices in accordance with provisions of the FASB’s Accounting Standards Update No. 2010-03, “Extractive Activities—Oil and Gas (Topic 932).” Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis and net operating losses associated with the properties. Since prices used in the calculation are average prices for 2016, 2017, and 2018, the standardized measure could vary significantly from year to year based on the market conditions that occurred during a given year.

The technical personnel responsible for preparing the reserve estimates at LaRoche Petroleum Consultants 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. LaRoche Petroleum Consultants is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. All reports by LaRoche Petroleum Consultants were developed utilizing studies performed by LaRoche Petroleum Consultants and assisted by the Engineering and Operations departments of Abraxas. Reserves are estimated by independent petroleum engineers. The report of LaRoche Petroleum Consultants dated February 12 2019, contains further discussions of the reserve estimates and evaluations prepared by LaRoche Petroleum Consultants as well as the qualifications of LaRoche Petroleum Consultants's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of proved reserves at December 31, 2016, 2017 and 2018 were based on studies performed by our independent petroleum engineers assisted by the Engineering and Operations departments of Abraxas. The Engineering department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Engineering is the manager of this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and has 40 years of experience in reserve evaluations. The Vice President of Engineering is a Registered Professional Engineer in the State of Texas. The operations department of Abraxas assisted in the process.

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The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted to represent the fair market value of the Company's proved oil and gas reserves. An estimate of fair market value would also take into account, among other factors, the recovery of reserves not 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.

Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure. The table below sets forth the Standardized Measure of our proved oil and gas reserves for the three years ended December 31, 2016, 2017 and 2018 (in thousands):

	Years Ended December 31,		
	2016	**2017**	**2018**
Future cash inflows	$999,716	$2,035,619	$2,876,976
Future production costs	(357,917)	(609,921)	(849,063)
Future development costs	(267,836)	(461,619)	(547,163)
Future income tax expense (1)	-	(83,915)	(181,224)
Future net cash flows	373,963	880,164	1,299,526
Discount	$(213,363)	$(474,423)	$(647,642)
Standardized Measure of discounted future net cash relating to proved reserves	$160,600	$405,741	$651,884

(1) There was no provision for future income tax expense for the year ended December 31, 2016 due to net operating loss carryovers.

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is an analysis of the changes in the Standardized Measure for the periods indicated (in thousands):

	Years Ended December 31,		
	2016	**2017**	**2018**
Standardized Measure, beginning of year	$197,251	$160,600	$405,741
Sales and transfers of oil and gas produced, net of production costs	(32,834)	(63,764)	(112,707)
Net change in prices and development and production costs from prior year	(58,425)	159,661	268,942
Extensions, discoveries, and improved recovery, less related costs	5,531	129,277	153,544
Sales of minerals in place	(4,433)	(8,583)	(39,253)
Purchases of minerals in place	-	1,238	8,990
Revisions of previous estimates	12,317	31,044	(67,345)
Change in timing and other	21,468	1,908	30,811
Change in future income tax expense	-	(21,700)	(37,413)
Accretion of discount	19,725	16,060	40,574
Standardized Measure, end of year	$160,600	$405,741	$651,884

The standardized measure is based on the following oil and gas prices over the life of the properties as of the following dates:

	Years Ended December 31,		
	2016	**2017**	**2018**
Oil (per Bbl) (1)	$42.74	$51.34	$65.56
Gas (per MMbtu) (2)	$2.50	$2.99	$3.05
Oil (per Bbl) (3)	$35.54	$46.83	$56.95
Gas (per MMbtu) (4)	$1.41	$1.79	$1.76
NGL's (per Bbl) (5)	$5.17	$13.19	$19.95

(1) The quoted oil price for the year ended December 31 of each year, 2016, 2017 and 2018 is the 12-month unweighted average first-day-of-the-month West Texas Intermediate spot price for each month of 2016, 2017 and 2018.

(2) The quoted gas price for the year ended December 31, 2016, 2017 and 2018 is the 12-month unweighted average first-day-of-the-month Henry Hub spot price for each month of 2016, 2017 and 2018.

(3) The oil price is the realized price at the wellhead as of December 31 of each year after the appropriate differentials have been applied.

(4) The gas price is the realized price at the wellhead as of December 31 of each year after the appropriate differentials have been applied.

(5) The NGL price is the realized price as of December 31 of each year after the appropriate differentials have been applied.

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Exhibit Index

23.1 Consent of BDO USA, LLP. (Filed herewith).

23.2 Consent of LaRoche Petroleum Consultants. (Filed herewith).

23.3 Consent of DeGoyler and MacNaughton. (Filed herewith).

31.1 Certification – Chief Executive Officer. (Filed herewith).

31.2 Certification – Chief Financial Officer. (Filed herewith).

32.1 Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).

32.2 Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).

99.1 Report of LaRoche Petroleum Consultants with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).

*Management Compensatory Plan or Agreement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ABRAXAS PETROLEUM CORPORATION

By: /s/Robert L.G. Watson President and Principal Executive Officer	By: /s/Steven P. Harris Vice President and Chief Financial Officer Principal Financial Officer	By: /s/ G. William Krog, Jr. Vice President and Chief Accounting Officer Principal Accounting Officer

DATED: March 15 , 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Signature	Name and Title	Date
/s/ Robert L.G. Watson Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	March 15, 2019
/s/ Steven P. Harris Steven P. Harris	Vice President, CFO (Principal Financial Officer)	March 15, 2019
/s/ G. William Krog, Jr. G. William Krog, Jr.	Vice President, Chief Accounting Officer (Principal Accounting Officer)	March 15, 2019
/s/ Harold D. Carter Harold D. Carter	Director	March 15, 2019
/s/ Ralph F. Cox Ralph F. Cox	Director	March 15, 2019
/s/ W. Dean Karrash	Director	March 15, 2019

W. Dean Karrash		
<u>/s/ Jerry J. Langdon</u>	Director	March 15, 2019
Jerry J. Langdon		
<u>/s/ Dennis E. Logue</u>	Director	March 15, 2019
Dennis E. Logue		
<u>/s/ Brian L. Melton</u>	Director	March 15, 2019
Brian L. Melton		
<u>/s/ Paul A. Powell, Jr.</u>	Director	March 15, 2019
Paul A. Powell, Jr.		
<u>/s/ Edward P. Russell</u>	Director	March 15, 2019
Edward P. Russell		