ABRAXAS PETROLEUM CORP
Form 10-K
March 15, 2016

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2015

r 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 Incorporation or Organization) | (I.R.S. Employer Identification Number) |

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. oYes No ý

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.Yes o No ý

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 ýNo

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 ý No o

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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 x No o

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 x |
| Non-accelerated filer (Do not check if a smaller reporting company) | Smaller reporting company |

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

As of June 30, 2015, 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 $295,066,931 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 10, 2016, there were 106,346,001 shares of common stock outstanding.

Documents Incorporated by Reference:

| Document | Parts Into Which Incorporated |
|---|---|
| Portions of the registrant's Proxy Statement relating to the 2016 Annual Meeting of Stockholders to be held on May 10, 2016. | Part III |

ABRAXAS PETROLEUM CORPORATION
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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 “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 restrictive debt covenants;
- 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;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- other factors discussed elsewhere in this report

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.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

“Mcfe” – thousand cubic feet of gas equivalent.

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“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.

“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.

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“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”).

“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. On October 31, 2014, we closed on the sale of our interest in Canadian Abraxas Petroleum, ULC (" Canadian Abraxas), an indirect wholly-owned Canadian subsidiary of Abraxas Petroleum Corporation. As a result of the disposal of Canadian Abraxas, the results of operations of Canadian Abraxas are reflected in our Financial Statements and in this report as “Discontinued Operations” and our remaining operations are referred to in our Financial Statements and in this report as “Continuing Operations” or “Continued Operations.” 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, 2015, our estimated net proved reserves were 43.2 MMBoe, of which 39.8% were classified as proved developed, 71% were oil and NGL and 95% of which (on a PV-10 basis) were operated by us. Our daily net production for the year ended December 31, 2015 was 5,975 Boepd, of which 77% was oil or liquids. 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 Rocky Mountain, Permian Basin and onshore Gulf Coast. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2015:

| | | | | | Estimated Net Proved Reserves | | | Net Production | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Producing Wells | Average Working Interest | | Total Net Acres | (MBoe) | % Oil/NGL | | (MBoe) | % Oil/NGL | |
| Rocky Mountain | 788 | 11.79 | % | 44,013 | 29,476 | 83.9 | % | 1,324.4 | 85.6 | % |
| Permian Basin | 240 | 64.22 | % | 28,370 | 10,106 | 40.3 | % | 293.6 | 44.7 | % |
| Onshore Gulf Coast | 78 | 82.71 | % | 14,141 | 3,608 | 52.5 | % | 562.8 | 73.5 | % |
| Total United States | 1,106 | 28.17 | % | 86,524 | 43,190 | 71.0 | % | 2,180.8 | 77.0 | % |

Our properties in the Rocky Mountain region are located in the Williston Basin of North Dakota and Montana and in the Green River, Powder River and Uinta Basins of Wyoming and Utah. In this region, our wells produce oil and gas from various reservoirs, primarily the Turner, Bakken, Three Forks and Red River formations. Well depths range from 7,000 feet down to 14,000 feet.

Our properties in the Permian Basin region are primarily located in two sub-basins, the Delaware Basin and the Eastern Shelf. In the Delaware Basin, our wells are located in Pecos, Reeves, and Ward Counties, Texas and produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet. In the Eastern Shelf, our wells are principally located in Coke, Scurry, Mitchell and Nolan Counties, Texas and produce oil and gas from the Strawn Reef formation at 5,000 to 7,500 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet.

Our properties in the onshore Gulf Coast region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas, the Eagle Ford shale in Atascosa and McMullen Counties, Texas and in the Portilla field in San Patricio County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation at a depth of 14,000 feet. In the Eagle Ford, our wells produce from the Eagle Ford shale from 8,000 to 11,000 feet, and in the Portilla field, our wells produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.

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2016 Outlook

Market prices for oil, gas and NGL are inherently volatile. Accordingly, we cannot predict with certainty the future prices for the commodities we produce and sell. Current market fundamentals indicate prices for oil, gas and NGL will continue to be depressed for much of 2016. Although changes in OPEC production strategies, geopolitical risks or other factors could impact current forecasts, we anticipate weak commodity prices throughout 2016. Depressed prices for oil and gas will likely have a material adverse effect on our results of operations and liquidity. Our primary sources of liquidity are cash flow from operations and borrowings under our credit facility. Cash flow from operations is sensitive to many variables, the most volatile of which is the price of the oil, gas and NGL we produce and sell. Our consolidated cash flow from operations decreased in 2015 as a result of the significant decrease in commodity prices. Availability under our credit facility is currently subject to a borrowing base of $165.0 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. Given the ongoing decline in commodity prices for oil, gas and NGL, it is likely that reductions in our borrowing base could arise in 2016.

In 2015, as a result of the sharp decline in commodity prices, we incurred an impairment to our proved properties of $128.6 million. We expect to record additional impairments of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month average oil and gas prices through March 1, 2016 of $46.04 per Bbl of oil and $2.48 per Mcf of gas being held constant for the trailing 12-month period, we estimate that we will record a ceiling test write down on our existing assets of approximately $30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of $72.7 million for the remainder of the year ending December 31, 2016. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While we will continue to operate and develop our portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs to be within our cash flow from operations. As a result, we are significantly reducing our capital budget in response to lower commodity prices. We are also committed to reducing our G&A and field-level operating costs commensurate with our reduced, but focused, activity level. Effective February 1, 2016, the named executive officers of Abraxas took a voluntary salary reduction of 20% and other employees, depending on salary thresholds, took voluntary cuts of 10% - 20%. It is anticipated that these reductions will reduce G&A cost by approximately $0.8 million during 2016.

Strategy

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

Focusing our capital and resources on our core operated basins.   Our core basins consist of the Williston Basin (Bakken/Three Forks), onshore Gulf Coast (Eagle Ford shale), which primarily produce oil and liquids, and the Permian Basin and Powder River Basin, which primarily produce gas.  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.  Thus, substantially all of our 2016 estimated capital expenditures will be in completing wells which have already been drilled in the Bakken, Three Forks.  As part of our efforts to focus our property portfolio, we are continually marketing 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 four core basins. Any proceeds from these asset sales will be used to reduce our indebtedness and/or redeployed into our core operating basins.

Maintaining financial flexibility. Our primary sources of capital are availability under our credit facility and cash flow from operations. At December 31, 2015 we had approximately $31.0 million of availability under our credit facility and for the year ended December 31, 2015, we generated approximately $7.0 million of cash flow from operations. Availability under our credit facility is subject to a borrowing base which is determined semi-annually by our lenders. The next borrowing base redetermination is scheduled to be effective on April 1, 2016. We seek to reduce the volatility of our cash flow from operations by hedging a portion of our production. We plan on deploying our available capital in a cost-effective manner. We seek to operate a high percentage of our properties which allows us to better control costs. At December 31, 2015, we operated properties comprising 95% of our proved developed reserves on a PV-10 basis. We intend to maintain

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our liquidity and the strength of our balance sheet during 2016 by adjusting our capital budget and seeking to reduce G&A and other expenses.

Profitably grow production and reserves. We have a substantial low-decline legacy production base as evidenced by our over 21 year reserve life as of year-end 2015. 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 rig in the Williston Basin, and heightened focus on cost control in all of our operated positions both contribute to our history of adding low cost barrels to our production base.

2016 Budget and Drilling Activities

Our capital expenditure budget for 2016 is approximately $40.0 million. This budget assumes an improvement in commodity prices by the summer of 2016, and re-starting the Raven Rig #1. However, if commodity prices stay at current levels or decline further and we elect to keep the Raven Rig #1 idled, our capital expenditures could be approximately $17.5 million which we intend to fund primarily with cash flows from operations. Substantially all of the $17.5 million would be spent on completing previously drilled wells in the Bakken/Three Forks in the Rocky Mountain region. These wells are classified as PDNP as of December 31, 2015. The 2016 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, 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 United States 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, 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 three way collars. 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, 2015, one purchaser of production accounted for approximately 54% of our oil and gas sales. During the year ended December 31, 2014, two purchasers of production accounted for approximately 62% 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 2013 to 2015.

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. We possess all material requisite permits required by the states and other local authorities in which we operate properties. 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 such as hazardous materials certificates, which we have obtained.

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.

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.

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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.

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 oil production 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, OSHA, 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.

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. 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:

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- require the acquisition of a permit or other authorization before construction or drilling commences;
- impose design and construction requirements on facilities in conjunction with oil and gas operations, including the construction of pollution control devices;
- require protective measures to prevent drilling 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;
- restrict the availability of water necessary for hydraulic fracturing operations;
- impose substantial penalties for violations of environmental rules or pollution resulting from our operations; and
- curtail production in association with 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.

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 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 currently 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 operating requirements and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. Analogous state laws further impose requirements associated with the management of solid 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 processing 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. EPA and the U.S. Army Corps of Engineers have adopted a rule that arguably expands the scope of “waters of the United States” that are regulated under the CWA. This rule could impact our operations by subjecting new waters to regulation; however, enforcement of the rule has been stayed while it is undergoing legal challenge in the federal courts. 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. 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 rules for injection wells aimed at reducing the potential for earthquakes associated with injection activities. We currently own and operate various underground injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. 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 operations 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 and has proposed rules that are still under review, including regulations which impose new restrictions on 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 oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. EPA has adopted a new ozone standard which will result in additional areas being designated as nonattainment and therefore subject to more stringent rules and permitting requirements. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Oil and gas exploration and production facilities may be required to incur certain 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.  However, bills such as the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2015 have been introduced in Congress to subject hydraulic fracturing to federal regulation under laws such as the Safe Drinking Water Act. If adopted, these bills could result in additional chemical disclosure and permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, these bills would require the public disclosure of information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In May 2015 the EPA released its draft report, assessment of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. This report has been under public and EPA review and has not yet been finalized. Also, in March 2015, the U.S. Department of the Interior, Bureau of Land Management ("BLM") released final regulations, in 2015, concerning hydraulic fracturing on federal and tribal lands, including chemical disclosure. These rules are currently under judicial challenge. In addition to these federal

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legislative and regulatory proposals, 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 high-volume hydraulic fracturing of horizontal wells, 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 water available for hydraulic fracturing.  If these types of conditions are widely adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells. Some states in which we operate have implemented disclosure requirements for chemicals used in hydraulic fracturing. Additional information concerning hydraulic fracturing is included under Item 1A. related to risk factors.

Climate Change Legislation and Greenhouse Gas Regulation. Studies over recent years 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 the United Nations Framework Convention on Climate Change, and the “Kyoto Protocol.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered “greenhouse gases” regulated by the Kyoto Protocol. In December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020. It is possible that the Paris Agreement 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. 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 that may arise from the Paris Agreement, 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 have adopted legislation and regulations to reduce emissions of greenhouse gases. 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. As a result of the U.S. Supreme Court decision in Massachusetts, et al. v. EPA, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, the EPA has issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA.  These regulations may apply to our operations. The EPA has adopted other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and gas exploration and production industry and the pipeline industry. Moreover, in January 2015, the Obama Administration announced that it would directly regulate methane emissions from the oil and gas industry as part of its climate strategy. Although the announcement gave no details on the upcoming regulations, it warned that the oil and gas sector will need to reduce its methane emissions by 40 to 50 percent from 2012 emission levels by 2025. Subsequently, on September 18, 2015, the EPA proposed three rules and issued a notice of availability of a draft Control Techniques Document relating to air emissions from the oil and gas industry. Further, on November 27, 2015, the EPA requested information related to hazardous air pollutant emissions from oil and gas operations. Additional rules from the EPA, BLM, and Department of Energy are expected under the EPA's methane plan. The EPA’s finding, the greenhouse gas reporting rule, the methane plan and the other rules to regulate the emissions of greenhouse gases may affect the cost of our operations and also affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Although various climate change legislative measures have been under consideration by the U.S. Congress, it is not possible at this time to predict when, or if, Congress will act on climate change legislation.  Finally, some states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular jurisdiction of our operations, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations. 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. related to risk factors.

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 would 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.

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 consent decrees involving the U.S. Fish and Wildlife Service which require the agency to decide whether or not to list, as endangered or threatened, approximately 251 candidate species by 2016. Included in this group are a number of species which, if listed, could include habitat in areas where we operate or plan to operate. Further, some of the species could become subject to voluntary rangeland conservation plans that could affect our operations. 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 10, 2016, we had 99 full-time employees. We retain independent geological, land, marketing and engineering 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

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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.

Item 1A. Risk Factors

Risks Related to Our Business

A continued substantial or extended decline in 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. Since the second half of 2014, there has been a significant decline in oil, gas and NGL prices, which adversely affected our 2015 operating results and contributed to a reduction in our anticipated future capital expenditures. In addition, this decline in commodity prices has adversely impacted our estimated proved reserves and resulted in a proved property impairment of $128.6 million to our oil and gas properties during 2015.

We expect to record an additional impairment of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month unweighted average oil and gas prices through March 1, 2016 of $2.48 per Mcf of gas and $46.04 per Bbl of oil being held constant for trailing 12-month period, we estimate that, we will record a ceiling test write down on our existing assets of approximately $30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of $72.7 million for the remainder of the year ending December 31, 2016. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

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;
- limiting our financial flexibility, liquidity and access to sources of capital, such as equity and debt;
- reducing our revenues, operating cash flows and profitability;
- causing us to further 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;

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- 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, the 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.

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 $165.0 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. Given the ongoing decline in commodity prices for oil, gas and NGL, it is likely that reductions in our borrowing base could arise from a number of factors, including:

- a reduction in reserve estimates;
- lower commodity prices or production;
- 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 15, 2016, we had $134.0 million of borrowings outstanding 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 operation and cash flow. 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 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 or continue to 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.

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

At December 31, 2015, we had a total of $134.0 million of indebtedness under our credit facility and total indebtedness of $140.7 million (including the current portion). 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 or at all;

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

- we may need 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

- our level of indebtedness will make 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 effect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of our credit facility, including borrowings in excess of the borrowing base or 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.

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.

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 further downturn in our business or the economy in general or otherwise conduct necessary or desirable business activities.

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A breach of any of these covenants could result in a default under our credit facility. 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 flow 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 modernized 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.

At December 31, 2014, the net capitalized costs of our oil and gas properties did not exceed the present value of our estimated proved reserves. For 2015, the net capitalized of our oil and gas properties exceeded the present value of our proved reserves, resulting in recognition of impairments in the third and fourth quarters totaling $128.6 million. If commodity prices remain at depressed levels or decrease further, we would likely be required to write down the carrying value of our reserves during 2016 which would also reduce our net income. Based on the 12-month average oil and gas prices through March 1, 2016 of $46.04 per Bbl of oil and $2.48 per Mcf of gas being held constant for the trailing 12-month period we estimate that we will record a ceiling test write down on our existing assets of approximately $30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of $72.7 million for the remainder of the year ending December 31, 2016.

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 flow 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 contract related to certain gas and NGL in the Rocky Mountain Region, that if certain margins of gas and NGL prices are not met by the purchaser, we receive no sales proceeds.

During 2015, differentials averaged $(7.61) per Bbl of oil and $(0.69) per Mcf of gas. Approximately 68% of our oil and NGL production during 2015 was from the Rocky Mountain region. Historically, this region has experienced wider differentials than our Permian Basin and Gulf Coast properties. If the percentage of our production from the Rocky Mountain region continues to increase, we expect that the effect of 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.

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

To achieve more predictable cash flow 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 and three way collars on approximately 62% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2015) through December 31, 2016 and 29% for 2017. 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

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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 flow from operations could be affected if the basis differentials widen more than we anticipate. We currently do not have any basis differential hedging arrangements in place. Our cash flow 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 flow from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows.

If the prices at which we hedge our oil and gas production are less than current market prices, our cash flow opportunity 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, 2015, we recognized a realized gain on oil and gas derivative contracts of $9.5 million and an unrealized gain of $9.8 million. The realized gain resulted in an increase 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 flow.

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 flow.

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, 2015 include proved undeveloped reserves and proved developed reserves that are behind pipe of 16,586 MBbls of oil, 4,903 MBbls of NGLs and 48,254 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, 2015 were undeveloped, and those proved reserves may not ultimately be developed.

At December 31, 2015, approximately 60 percent of the Company's total estimated proved reserves on a BOE basis (19% on a PV-10 basis) were undeveloped. Recovery of undeveloped proved 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 proved 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 flow and income are highly dependent on successfully developing its proved undeveloped leasehold acreage.

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 flow from operations, borrowings under credit facilities, sales of producing properties, and sales of debt and equity securities and we expect to continue to do so in the future. 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 flow from operations. Lower prices and/or lower production could also decrease revenues and cash flow, 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 flow from operations does not increase as a result of planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

The borrowing base under our credit facility is determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under our credit facility to meet our capital requirements and/or trigger certain repayment obligations. Such a reduction could be the result of lower commodity prices and/or production, an inability to drill or unfavorable drilling results, changes in oil and gas reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

If cash flows from operations or our borrowing base decreases, 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 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.

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, 2015, our average annual estimated decline rate for our net proved developed producing reserves is 33%; 26%; 15%; 11% and 10% in 2017, 2018, 2019, 2020 and 2021, respectively, 10% in the next five years, and approximately 12% 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 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 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) at December 31, 2015 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 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) as of December 31, 2015 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. In addition, our properties may be susceptible to drainage from production by other operations on adjacent properties. If the volume of oil and gas we produce decreases, our cash flow 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.

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.

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

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We currently do not operate all of the properties in which we have an interest. 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.

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 and the Powder River Basins, drilling and other oil and gas activities cannot be conducted as effectively 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 is 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;
- 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.

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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, shoreline contamination, 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, has recently come under increased scrutiny and 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 prospective rock 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 recently implemented disclosure requirements related to chemicals used in hydraulic fracturing, and the U.S. Department of the Interior, Bureau of Land Management (“BLM”) released final rules in March 2015 governing hydraulic fracturing on federal and tribal lands, including requiring chemical disclosure.  BLM's rules are currently under judicial challenge. 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 April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing, and planning among federal agencies and offices regarding “unconventional natural-gas production,” including hydraulic fracturing. In May 2014, the EPA announced its intent to initiate rulemaking regulations under the Toxic Substances Control Act to obtain data on chemical substances and mixtures used in hydraulic fracturing.  In August 2012, the EPA published final rules under the CAA, which became effective October 15, 2012, that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and

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combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 or performing reduced emission completions, also known as "green completions," with or without combustion devices, on or after January 1, 2015. 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. Moreover, the BLM has adopted final rules that impose more stringent technical requirements and the disclosure of chemicals used in hydraulic fracturing operations on public and Native American lands. These rules are currently under judicial challenge. 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. For example, Texas adopted a law in June 2011 requiring disclosure to the Texas Railroad Commission and the public disclosure of certain information regarding the components used in the hydraulic-fracturing process. 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.

Certain governmental reviews were recently conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not lead to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA's Science Advisory Board provided its comments on the draft study, indicating its concern that the EPA's conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Moreover, on April 7, 2015, the EPA proposed pre-treatment standards addressing the discharge of wastewater pollutants from hydraulic fracturing operations to publicly owned treatment works. The EPA is also conducting a study of private wastewater treatment facilities that accept oil and gas extraction wastewater. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. See "Item 1. Business – Environmental Matters – Hydraulic Fracturing" above for additional discussion related to environmental risks associated with our hydraulic fracturing activities.

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 US. 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

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- 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;
- 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.

Our need to incur costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities that are 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 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. Transportation space on such gathering systems and pipelines is occasionally 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 our access to these transportation and storage options dramatically changes, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas.

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 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 exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, the CFTC has 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, the CFTC has 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 could increase the costs to us of entering into derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on 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, these rules and regulations may require us to comply with position limits and with certain clearing and trade-execution requirements in connection with our financial derivative activities The Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared derivative contracts with us, which could increase the cost to us of entering into such derivative contracts. 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 financial derivatives with us, which could increase our costs of future financial derivative transactions. 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 financial 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.

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, 2015, we had a net operating loss ("NOL") carryforward for federal income tax purposes of $192.9 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 NOL 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. In addition, under the Code, NOL can generally be carried forward to offset future taxable income for a period of 20 years. Our ability to use our NOL during this period will be dependent on our ability to generate taxable income, and the NOL 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 losses in the future. We did have a cyber attack in 2010 relating to electronic bank transfers, although the monetary loss was very minimal, additional procedures were implemented to safeguard against future cyber attacks. 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 and 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 cause, 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, profitability and growth.

Our revenue, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Prices also affect the amount of cash flow 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.

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, 2015 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 PV-10 thereof for 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, 2015. The average realized sales prices as of such date used for purposes of such estimates were $2.36 per Mcf of gas and $41.25 per Bbl of oil. The December 31, 2015 estimates also assume that we will make future capital expenditures of approximately $338.3 million

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in the aggregate primarily from 2016 through 2021, 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 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) as of December 31, 2015 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, 2015 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2015 and costs in effect on December 31, 2015, 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 flow, 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.

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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.

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

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.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of gas, and carbon dioxide, a by-product of the burning of oil, gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change and the Kyoto Protocol address greenhouse gas emissions, and several countries including the European Union have established greenhouse gas regulatory systems. In December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020. It is possible that the Paris Agreement 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, several states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs. At the federal legislative 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 the U.S. House of Representatives. 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.

As a result of the U.S. Supreme Court decision in Massachusetts, et al. v. EPA, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, the EPA has issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. These regulations may apply to our operations. The EPA has adopted other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and gas exploration and production industry and the pipeline industry. Further, on September 18, 2015, the EPA proposed three rules and issued a notice of availability of a draft Control Techniques Document relating to air emissions (including GHG emissions) from the oil and gas industry. These rules are expected to be finalized in 2016. The EPA's finding, the greenhouse gas reporting rule, and the rules to regulate the emissions of greenhouse gases may affect the cost of our operations and also affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases 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.

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

In October 2015, the U.S. Environmental Protection Agency (EPA) issued 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. The final rule became effective in December 2015. Certain areas of the country in compliance with the ground-level ozone NAAQS standard may be reclassified as non-attainment and such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement more stringent regulations necessary to come into compliance with the new NAAQS, which could apply to our operations. Compliance with these final rules could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

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.

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.

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 200,000,000 shares of common stock with such rights as determined by our board of directors.  We may in the future 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.

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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, 2015, we had 106,346,001 shares of common stock outstanding of which 9,639,046 shares were held by affiliates and, in addition, 6,807,729 shares of common stock were subject to outstanding options granted under stock option plans (of which 4,305,228 shares were vested at December 31, 2015).

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.

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.

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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, 2015.

| | Developed Acreage | | Undeveloped Acreage | | Fee Mineral Acreage (1) | | |
|---|---|---|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres | Gross Acres | Net Acres | Total Net Acres (2) |
| Rocky Mountain | 36,855 | 22,108 | 32,957 | 21,590 | 2,758 | 316 | 44,014 |
| Permian Basin | 17,766 | 14,967 | 10,226 | 8,130 | 12,008 | 5,273 | 28,370 |
| Onshore Gulf Coast | 8,166 | 7,654 | 5,827 | 5,608 | 2,975 | 879 | 14,141 |
| Total | 62,787 | 44,729 | 49,010 | 35,328 | 17,741 | 6,468 | 86,525 |

(1) Fee mineral acreage represents fee simple absolute ownership of the mineral estate or fraction thereof.
(2) Includes 1,217 net acres in the Permian Basin region that are included in both developed and fee mineral acres.

The flowing table sets forth Abraxas’ net undeveloped acreage subject to expire by year:

| | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|
| Rocky Mountain | 280 | — | 647 | — |
| Permian Basin | 822 | 79 | — | — |
| Onshore Gulf Coast | 672 | 3,078 | 149 | — |

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2015:

| | Productive Wells | | | |
|---|---|---|---|---|
| | Oil | | Gas | |
| | Gross | Net | Gross | Net |
| Rocky Mountain | 376.0 | 81.7 | 412.0 | 11.2 |
| Permian Basin | 189.0 | 126.5 | 51.0 | 27.6 |
| Onshore Gulf Coast | 50.5 | 39.1 | 27.5 | 25.4 |
| Total | 615.5 | 247.3 | 490.5 | 64.2 |

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.

For the year ended December 31, 2015, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for Abraxas' 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 DeGolyer and MacNaughton to prepare reserve estimates for these properties as they are located in a widely dispersed geographic area and have relatively low

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value. DeGolyer and MacNaughton's reserve report as of December 31, 2015 included a total of 335 properties and our internal report included 343 properties.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton 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. DeGolyer and MacNaughton 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 DeGolyer and MacNaughton were developed utilizing their own geological and engineering data, supplemented by data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 4, 2016, which contains further discussions of the reserve estimates and evaluations prepared by DeGolyer and MacNaughton as well as the qualifications of DeGolyer and MacNaughton'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, 2015 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 37 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, include oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages which are 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 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, 2015, 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, 2015. All of our reserves are located in the United States.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2015

| Reserve Category | Oil (MBbls) | NGL (MBbls) | Gas (MMcf) | Oil Equivalents (MBoe) |
|---|---|---|---|---|
| Proved | | | | |
| Developed | 10,022 | 1,957 | 31,298 | 17,194 |
| Undeveloped | 14,109 | 4,599 | 43,729 | 25,996 |
| Total Proved | 24,131 | 6,556 | 75,027 | 43,190 |

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2013, 2014, and 2015, 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, 2015. 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, 2015 report. The average realized sales prices used for purposes of such estimates were $41.25 per Bbl of oil and $2.36 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $338.3 million in the aggregate primarily in the years 2016 through 2021, 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 flow 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, 2015, the Company’s net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves, resulting in a proved property impairment of $128.6 million. If commodity prices remain at depressed levels or decrease further, we could be required to further write down the carrying value of our reserves during 2016 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.

Proved Undeveloped Reserves

Changes in PUDs. Significant changes to PUDs occurring during 2015 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 period. 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 are no PUDs as of December 31, 2015, included in this report that are not planned to be developed within five years.

| | MMBoe |
|---|---|
| PUDs at December 31, 2014 | 24,459 |
| Revisions of prior estimates | (8,582 ) |
| Extensions, discoveries, and other additions | 15,333 |
| Conversion to developed | (5,214 ) |
| Sales | — |
| PUDs at December 31, 2015 | 25,996 |

We spent approximately $57.9 million converting 15 proved undeveloped reserves cases to proved developed reserves in 2015. These 15 wells represent 2.6 MMBOE of reserves. The Company also added approximately 600 MBOE in net proved undeveloped reserves as the result of upward revisions in the Bakken PUD projections based on existing well performance.

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We also added 28 new proved undeveloped Bakken locations on the Company's prospect acreage in McKenzie County, North Dakota, accounting for approximately 6.5 MMBOE of net reserves, 20 of which are in the Three Forks (second bench) locations which were proved during 2015 by local development results. There were also 8 downspaced locations added on the Yellowstone Unit by virtue of the fact that operatorship of that unit passed to Abraxas during 2015 thereby allowing the implementation of the Company's standard Bakken spacing plan.
We also gained proved undeveloped reserves of approximately 1.4 MMBOE net, due to the change in classification of 21 probable and possible undeveloped Bakken cases into the proved category. These locations achieved proved status by virtue of offsetting development activity during 2015. An equivalent volume of reserves was removed from the probable and possible undeveloped category as a result of this change in classification.
We also added 6 new Montoya proved undeveloped locations on the Company's prospect acreage in Ward County, Texas. These locations were added based on the performance of existing Montoya producers on the subject leasehold. Net reserves of approximately 6.5 MMBOE are attributable to these new locations.
We dropped 38 South Texas Eagle Ford proved undeveloped cases from our reserve report due to lack of economic viability at the lower commodity prices. These cases represented approximately 7.8 MMBOE of net reserves.
For the period ending December 31, 2015, proved producing reserves decreased by approximately 6.6 MMBOE, net, due primarily to shortened economic lives resulting from lower product price forecasts.

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 PV-10 to the standardized measure of discounted future net cash flows at December 31, 2014 and 2015:

| | December 31, | |
|---|---|---|
| | 2014 | 2015 |
| | (In thousands) | |
| PV-10 | $637,443 | $197,251 |
| Present value of future income taxes discounted at 10% | (124,886 ) | — |
| Standardized measure of discounted future net cash flows | $512,557 | $197,251 |

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 NGLs 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:

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| Oil production (Bbls) | | | |

| | | | |
|---|---|---|---|
| Rocky Mountain | 501,657 | 816,323 | 1,000,425 |
| Permian Basin | 100,846 | 86,614 | 76,391 |
| Onshore Gulf Coast | 224,625 | 491,142 | 363,404 |
| Mid-Continent (1) | 2,197 | — | — |

| | | | |
|---|---|---|---|
| Total | 829,325 | 1,394,079 | 1,440,220 |
| Gas production (Mcf) | | | |
| Rocky Mountain | 940,969 | 1,057,759 | 1,146,953 |
| Permian Basin | 1,288,198 | 1,003,018 | 973,840 |
| Onshore Gulf Coast | 1,029,346 | 856,928 | 894,039 |
| Mid-Continent (1) | 84,384 | — | — |
| Total | 3,342,897 | 2,917,705 | 3,014,832 |
| NGL production (Bbls) | | | |
| Rocky Mountain | 50,421 | 95,384 | 132,846 |
| Permian Basin | 88,254 | 79,321 | 54,877 |
| Onshore Gulf Coast | 7,871 | 32,592 | 50,392 |
| Mid-Continent (1) | 178 | — | — |
| Total | 146,724 | 207,297 | 238,115 |
| Total production (MBoe) (2) | 1,533 | 2,088 | 2,181 |
| Average sales price per Bbl of oil (3) | | | |
| Rocky Mountain | $87.80 | $78.59 | $39.23 |
| Permian Basin | $91.72 | $84.38 | $44.69 |
| Onshore Gulf Coast | $101.59 | $88.44 | $45.71 |
| Mid-Continent (4) | $90.53 | $— | $— |
| Composite | $92.02 | $82.42 | $41.15 |
| Average sales price per Mcf of gas (3) | | | |
| Rocky Mountain | $3.33 | $4.41 | $1.46 |
| Permian Basin | $3.47 | $4.29 | $2.24 |
| Onshore Gulf Coast | $2.99 | $3.73 | $2.24 |
| Mid-Continent (1) | $2.87 | $— | $— |
| Composite | $3.27 | $4.17 | $1.94 |
| Average sales price per Bbl of NGL | | | |
| Rocky Mountain | $40.59 | $36.41 | $5.49 |
| Permian Basin | $32.12 | $31.10 | $13.03 |
| Onshore Gulf Coast | $18.96 | $21.41 | $8.60 |
| Mid-Continent (1) | $30.09 | $— | $— |
| Composite | $34.32 | $32.02 | $7.89 |
| Average sales price per Boe (3) | $60.18 | $64.04 | $30.72 |
| Average cost of production per Boe produced (4) | | | |
| Rocky Mountain | $13.11 | $7.36 | $6.43 |
| Permian Basin | $14.50 | $15.15 | $15.76 |
| Onshore Gulf Coast | $8.34 | $9.30 | $12.71 |
| Mid-Continent (1) | $15.65 | $— | $— |
| Composite | $12.71 | $9.22 | $9.31 |

(1) All of our Mid-Continent properties were sold in 2013.
(2) Oil and gas were combined by converting gas to a Boe equivalent on the basis of 6 Mcf of gas to 1 Bbl of oil.
(3) Before the impact of hedging activities.
(4) Production costs include controllable direct lease operating costs but exclude ad valorem taxes, production taxes and non-recurring lease operating costs.

Within the above major operating regions, the Rocky Mountain and Onshore Gulf Coast regions represented more than 15% of our proved reserves as of December 31, 2015. The following is a summary, by product sold, for each primary field in these regions for the three years ended December 31, 2015:

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| | 2013 | 2014 | 2015 | |
|---|---|---|---|---|
| Rocky Mountain Region | | | | |
| Oil production (Bbls) | | | | |
| Bakken/Three Forks | 296,451 | 660,447 | 862,458 | |
| Gas production (Mcf) | | | | |
| Bakken/Three Forks | 351,248 | 570,792 | 687,200 | |
| NGL production (Bbls) | | | | |
| Bakken/Three Forks | 31,229 | 77,120 | 116,392 | |
| Average sales price per Bbl of oil (1) | | | | |
| Bakken/Three Forks | $88.35 | $78.01 | $39.15 | |
| Average sales price per Mcf of gas (1) | | | | |
| Bakken/Three Forks | $2.87 | $4.60 | $1.07 | |
| Average sales price per Bbl of NGL (1) | | | | |
| Bakken/Three Forks | $37.34 | $34.86 | $3.78 | |
| Average cost of production per Boe produced (2) | | | | |
| Bakken/Three Forks | $10.03 | $6.88 | $4.05 | |
| | | | | |
| Onshore Gulf Coast Region | | | | |
| Oil production (Bbls) | | | | |
| Eagle Ford | 154,910 | 431,892 | 305,797 | |
| Gas production (Mcf) | | | | |
| Eagle Ford | 45,560 | 229,385 | 325,942 | |
| NGL production (Bbls) | | | | |
| Eagle Ford | 7,530 | 32,592 | 50,392 | |
| Average sales price per Bbl of oil (1) | | | | |
| Eagle Ford | $102.17 | $88.30 | $45.87 | |
| Average sales price per Mcf of gas (1) | | | | |
| Eagle Ford | $3.11 | $3.69 | $2.44 | |
| Average sales price per Bbl of NGL | | | | |
| Eagle Ford | $18.48 | $21.42 | $8.60 | — |
| Average cost of production per Boe produced (2) | | | | |
| Eagle Ford | $6.40 | $7.98 | $12.33 | |

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

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:

| | 2013 | | 2014 | | 2015 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Exploratory | | | | | | |
| Productive | | | | | | |
| Rocky Mountain | — | — | — | — | — | — |
| Permian Basin | — | — | — | — | — | — |

| | | | | | | |
|---|---|---|---|---|---|---|
| Onshore Gulf Coast | — | — | — | — | — | — |
| Total | — | — | — | — | — | — |
| Dry wells | | | | | | |
| Permian Basin | 2.0 | 2.0 | — | — | — | — |

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| | | | | | | |
|---|---|---|---|---|---|---|
| Total | 2.0 | 2.0 | — | — | — | — |
| Development | | | | | | |
| Productive | | | | | | |
| Rocky Mountain | 31.0 | 3.1 | 10.0 | 6.4 | 21.0 | 6.8 |
| Permian Basin | 1.0 | 1.0 | — | — | — | — |
| Onshore Gulf Coast | 11.0 | 3.9 | 10.0 | 10.0 | 4.0 | 4.0 |
| Total | 43.0 | 8.0 | 20.0 | 16.4 | 25.0 | 10.8 |

In addition to the above drilling activity, as of December 31, 2015 we had 6.0 gross (4.7 net) operated wells and 1.0 gross (0.37 net) non-operated well that were drilled and uncompleted, that are not represented in the above table.

Present Activities

As of March 10, 2016, we had six gross (4.7 net) operated wells and 1.0 gross (0.37 net) non-operated well that are drilled and waiting for completion later in 2016.

In the following discussion, production rates do not include the impact of NGL production and shrinkage from processing including the flaring of gas. The following provides an overview of our present activities:

Williston Basin

At Abraxas' North Fork prospect, in McKenzie County, North Dakota, the Sten-Rav 1H and Ravin 8H producing from the Three Forks, averaged 900 boepd (678 barrels of oil per day, 1,332 mcf of natural gas per day) over the wells' peak 30 days of production. The Stenehjem 5H producing from the Middle Bakken, averaged 809 boepd (604 barrels of oil per day, 1,232 mcf of natural gas per day) over the well's peak 30 days of production. Each well was constrained on a smaller than normal choke to minimize flaring. Abraxas owns a working interest of approximately 76% in the Ravin Northwest wells.

On the Stenehjem Super Pad, Abraxas successfully drilled and cased the Stenehjem 10H-15H. These six wells are scheduled for completion in the third quarter of 2016. Abraxas owns a working interest of approximately 78% in the Stenehjem 10H-15H. Offsetting these six wells, Abraxas recently agreed to participate in a unit line well drilled by another operator where Abraxas holds a 36% working interest. All seven wells are now drilled and are waiting on completion. Abraxas has idled Raven Rig #1 until commodity prices improve.

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. The note bears interest at a fixed rate of 4.25%, and is payable in monthly installments of principal and interest of $34,354. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The note matures in July 2023. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2015, $4.1 million was outstanding on the note. We lease office space in Dickinson, North Dakota for a monthly rental of $2,320 through October 2016. The lease expires on October 31, 2016. We lease office space in Lusk, Wyoming for a monthly rental of $750. The lease expires on December 31,

2016. We also lease office space in Denver, Colorado for a monthly rental of $959. The lease expires on December 31, 2016.

Other Properties

We own 1,769 acres of land, including an office building, workshop, warehouse and house in San Patricio County, Texas, 613 acres of land and an office building in Scurry County, Texas, 50 acres of land in DeWitt County, Texas, 582 acres of land in McKenzie County, North Dakota and 12,178 acres of land in Pecos County, Texas.

We own 32 vehicles which are used in the field by employees. We own two workover rigs, which are used for servicing our wells. Raven Drilling owns a 2000 HP drilling rig, primarily to be used for drilling wells in the Williston Basin. We own three houses in North Dakota and a man-camp in North Dakota 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, 2015, 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 |
|---|---|---|---|---|
| 2014 | | | | |
| | | First Quarter | $4.15 | $2.99 |
| | | Second Quarter | 6.41 | 3.82 |
| | | Third Quarter | 6.45 | 4.81 |
| | | Fourth Quarter | 5.30 | 2.33 |
| 2015 | | | | |
| | | First Quarter | $3.56 | $2.60 |
| | | Second Quarter | 3.98 | 2.82 |
| | | Third Quarter | 2.95 | 1.20 |
| | | Fourth Quarter | 1.95 | 0.84 |
| 2016 | 16 | First Quarter (Through March 10, 2016) | $1.31 | $0.65 |

Holders

As of March 10, 2016, we had 106,346,001 shares of common stock outstanding and approximately 1,041 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 2015 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, the following list of comparable companies: Approach Resources, Inc. (AREX), Callon Petroleum Company (CPE), Clayton Williams Energy, Inc. (CWEI), Comstock Resources, Inc. (CRK), Contango Oil & Gas Company (MCF), Emerald Oil (EOX), Evolution Petroleum Corp. (EPM), Gastar Exploration Inc. (GST), Magnum Hunter Resources Corp. (MHR), Northern Oil and Gas, Inc (NOG), Penn Virginia Corporation (PVA), Swift Energy Co. (SFY), Triangle Petroleum Corporation (TPLM) and Warren Resources Inc. (WRES).

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, 2010, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2011, 2012, 2013, 2014 and 2015.

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| | 12/31/2010 | 12/31/2011 | 12/31/2012 | 12/31/2013 | 12/31/2014 | 12/31/2015 |
|---|---|---|---|---|---|---|
| Small Cap Index | $ 100.00 | $ 69.26 | $ 43.97 | $ 59.15 | $ 27.68 | $ 9.96 |
| S&P 500 | $ 100.00 | $ 100.00 | $ 113.40 | $ 146.97 | $ 163.71 | $ 162.52 |
| AXAS | $ 100.00 | $ 72.21 | $ 47.92 | $ 71.36 | $ 64.33 | $ 23.19 |

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, 2011 through 2015. 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, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 |
| | (In thousands, except per share data) | | | | |
| Total revenue - continuing operations | $63,105 | $65,664 | $92,324 | $133,776 | $67,030 |
| Net income (loss) | $13,743 | $(18,791) | $38,647 | $63,269 | $(127,110) |
| Net income (loss) from continuing operations | $14,395 | $3,106 | $46,841 (2) | $61,951 | $(127,090) (5) |
| Net (loss) income from discontinued operations | $(652) | $(21,897) (1) | $(8,194) (3) | $1,318 (4) | $(20) |
| Net income (loss) per common share – diluted - continuing operations | $0.15 | $0.04 | $0.50 | $0.61 | $(1.21) |
| Weighted average shares outstanding – diluted | 92,244 | 91,914 | 93,538 | 101,468 | 104,605 |
| Total assets | $241,150 | $240,607 | $223,650 | $374,899 | $267,872 |
| Long-term debt, excluding current maturities | $126,258 | $124,101 | $41,790 | $76,554 | $138,402 |
| Total stockholders' equity | $62,651 | $46,700 | $86,906 | $207,495 | $84,465 |

(1) Includes proved property impairment of $19.8 million related to discontinued operations.
(2) Includes a gain on the sale of properties of $33.4 million.
(3) Includes proved property impairment of $6.0 million related to discontinued operations.
(4) Includes a gain of $1.9 million on the sale of our Canadian subsidiary.
(5) Includes proved property impairment of $128.6 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 excludes the results of our Canadian subsidiary which was sold on October 31, 2014. The results of these foreign operations are included as discontinued operations in the accompanying Consolidated Financial Statements and Notes thereto.
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:

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- 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.

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 the 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 2016 will impact the amount of cash generated from operating activities, which will in turn impact our financial position. As of March 10, 2016, the NYMEX oil and gas price was $37.84 per Bbl of oil and $1.79 per Mcf of gas, respectively, representing declines of 22% and 31%, respectively, from the average NYMEX prices in 2015.

During 2015, the NYMEX future price for oil averaged $48.76 per barrel as compared to $92.91 per barrel in 2014. During 2015 the NYMEX future spot price for gas averaged $2.63 per MMBtu compared to $4.26 per MMBtu in 2014. Prices closed on December 31, 2015 at $37.04 per Bbl of oil and $2.34 per MMBtu of gas. If commodity prices remain at these levels or continue to decline, our revenue and cash flow 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 remain depressed or continue to decline, our revenues, profitability and cash flow 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 next scheduled to be redetermined on April 1, 2016.

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, 2013, 2014 and 2015:

| | Oil | | | Gas | | |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2013 | 2014 | 2015 |
| Average realized price (1) | $92.02 | $82.42 | $41.15 | $3.27 | $4.17 | $1.94 |
| Average NYMEX price | $98.06 | $92.91 | $48.76 | $3.73 | $4.26 | $2.63 |
| Differential | $(6.04) | $(10.49) | $(7.61) | $(0.46) | $(0.09) | $(0.69) |

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

The Company’s derivative contracts consist of NYMEX-based fixed price swaps and three-way collar contracts. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Three-way collar contracts combine a long put, a short put and a short call. Under a collar, we pay the counterparty if the market price is

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above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put). The use of the long put combined with a short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limits our exposure to future settlement payments while also restricting our downward risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle our contracts for the market price plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.

Our hedging arrangements equate to approximately 62% of the estimated oil production from our net proved developed producing reserves (as of December 31, 2015) through December 31, 2016, and 29% in 2017. 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 flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have in the past and will in the future sustain realized and unrealized losses on our 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 2013, we incurred a net loss of $2.5 million, consisting of a loss of $5.0 million related to closed contracts and a gain of $2.5 million related to open contracts. In 2014, we incurred a gain of $25.2 million, consisting of a gain of $0.3 million on closed contracts and a gain of $24.9 million related to open contracts. In 2015 we incurred a gain of $19.3 million, consisting of a gain of $9.5 million on closed contracts and a gain of $9.8 million related to open contracts. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at December 31, 2015:

Fixed Price Swaps:

| Contract Periods | Oil - WTI Daily Volume (Bbl) | Swap Price (per Bbl) |
|---|---|---|
| 2016 | 948 | $84.10 |
| 2017 | 608 | $78.55 |

Collar contracts combined with short puts (three way collars):

| | Daily Volume (Bbl) | Floor (Long Put) | Ceiling (Short Call) | Short Put |
|---|---|---|---|---|
| 2016 | 1,000 | $60.00 | $71.00 | $45.00 |

At December 31, 2015, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $27.4 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 estimates as of December 31, 2015, our average annual estimated decline rate for our net proved developed producing reserves is 33%; 26%; 15%; 11% and 10% in 2017, 2018, 2019, 2020 and 2021, respectively, 10% in the next five years, and approximately 12% 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.

We had capital expenditures during 2015 of $69.4 million related to our exploration and development activities. We have a capital expenditure budget for 2016 of approximately $40.0 million. This budget assumes an improvement in commodity prices by the summer of 2016, and re-starting the Raven Rig #1. However, if commodity prices stay at current levels or decline further and we elect to keep the Raven Rig #1 idled, our capital expenditures could be approximately $17.5 million which we intend to fund primarily with cash flows from operations. Substantially all of the $17.5 million would be spent on completing previously drilled wells in the Bakken/Three Forks in the Rocky Mountain region, which were classified as PDNP as of December 31, 2015. The 2016 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

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prices for oil and gas, the availability of sufficient capital resources including under our credit facility, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the years ended December 31, 2013, 2014 and 2015:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2014 | 2015 |
| Total production (MBoe) | 1,533 | 2,088 | 2,181 |
| Average daily production (Boepd) | 4,201 | 5,720 | 5,975 |
| % Oil/ NGL | 64 % | 77 % | 77 % |

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flow 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, 2015, we had approximately $31.0 million of availability under our credit facility and $3.5 million in cash. 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 April 1, 2016.

Borrowings and Interest. At December 31, 2015, we had a total of $134.0 million outstanding under our credit facility and total indebtedness of $140.7 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 high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2015, we operated properties accounting for approximately 95% of our PV-10, 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, 2015, we drilled or participated in 145 gross (55.8 net) wells of which 97% 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 flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 60% of our estimated proved reserves on a BOE basis (19% on a PV-10 basis) at December 31, 2015 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.

2016 Outlook

Market prices for oil, gas and NGL are inherently volatile. Accordingly, we cannot predict with certainty the future prices for the commodities we produce and sell. Current market fundamentals indicate prices for oil, gas and NGL will continue to be depressed for much of 2016. Although changes in OPEC production strategies, geopolitical risks or other factors could impact current forecasts, we anticipate weak commodity prices throughout 2016. Depressed prices for oil and gas will likely have a material adverse effect on our results of operations and liquidity. Our primary sources of liquidity are cash flow from operations and borrowings under our credit facility. Cash flow from operations is sensitive to many variables, the most volatile of which is the price of the oil, gas and NGL we produce and sell. Our consolidated cash flow from operations decreased in 2015 as a result of the significant decrease in commodity prices. Availability under our credit facility is currently subject to a borrowing base of $165.0 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

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unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Given the ongoing decline in commodity prices for oil, gas and NGL, it is likely that reductions in our borrowing base could arise in 2016.

In 2015, as a result of the sharp decline in commodity prices, we incurred an impairment to our proved properties of $128.6 million. We expect to record additional impairments of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month unweighted average oil and gas prices through March 1, 2016 of $46.04 per Bbl of oil and $2.48 per Mcf of gas being held constant for the trailing 12-month period we estimate that we will record a ceiling test write down on our existing assets of approximately $30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of $72.7 million for the remainder of the year ending December 31, 2016. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While we will continue to operate and develop our portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs to be within our cash flow from operations. As a result, we are significantly reducing our capital budget in response to lower commodity prices. We are also committed to reducing our G&A and field-level operating costs commensurate with our reduced, but focused, activity level. Effective February 1, 2016, the named executive officers of Abraxas took a voluntary salary reduction of 20% and other employees, depending on salary thresholds, took voluntary cuts of 10% - 20%. It is anticipated that these reductions will reduce G&A cost by approximately $0.8 million during 2016.

Results of Operations

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

| | Year Ended December 31, (In thousands, except per unit data) | | |
|---|---|---|---|
| | 2013 | 2014 | 2015 |
| Operating revenue (1): | | | |
| Oil sales | $76,311 | $114,898 | $59,270 |
| Gas sales | 10,921 | 12,166 | 5,854 |
| NGL sales | 5,036 | 6,637 | 1,878 |
| Total operating revenues | $92,268 | $133,701 | $67,002 |
| Operating income (loss) | $23,097 | $39,922 | $(141,805) |
| Oil sales (MBbls) | 829 | 1,394 | 1,440 |
| Gas sales (MMcf) | 3,343 | 2,918 | 3,015 |
| NGL sales (MBbls) | 147 | 207 | 238 |
| Oil equivalents (MBoe) | 1,533 | 2,088 | 2,181 |
| Average oil sales price (per Bbl)(1) | $92.02 | $82.42 | $41.15 |
| Average gas sales price (per Mcf)(1) | $3.27 | $4.17 | $1.94 |
| Average NGL sales price (per Bbl) | $34.32 | $32.02 | $7.89 |
| Average oil equivalent sales price (Boe) | $60.18 | $64.04 | $30.72 |

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

Comparison of Year Ended December 31, 2015 to Year Ended December 31, 2014

Operating Revenue. During the year ended December 31, 2015, operating revenue decreased to $67.0 million from $133.7 million in 2014. The decrease in revenue was primarily due to a significant decline in commodity prices in 2015. Lower commodity prices had a negative impact on revenue of $69.0 million in 2015. During 2015 we experienced a decline in the average realized oil price of approximately 50% from 2014 levels. Average realized gas prices declined by approximately 53% and average realized NGL prices declined approximately 75% from 2014 levels. Higher sales volumes of all products added $2.3 million to revenue in 2015 as compared to 2014.

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Oil sales volumes increased to 1,440 MBbls for the year ended December 31, 2015 from 1,394 MBbls for the same period of 2014. The increase in oil sales volumes was due to new production brought on line in 2015. New wells brought onto production in 2015 contributed 298 MBbls to production for the year ended December 31, 2015, offset by natural field declines and property sales. Gas sales volumes increased to 3,015 MMcf for the year ended December 31, 2015 from 2,918 MMcf for the year ended December 31, 2014. The increase in gas production was due to new wells being brought on line, offset by natural field declines. New wells brought onto production during 2015 contributed 299 MMcf to production for the year ended December 31, 2015. NGL sales increased to 238 MBbls for the year ended December 31, 2015 from 207 MBbls for the same period of 2014. The increase in NGL sales was primarily due to increased gas production from fields in West Texas, Wyoming 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, 2015 decreased to $23.1 million from $25.9 million in 2014. The decrease in LOE was primarily due to lower cost of services, and less non-recurring LOE in 2015 compared to 2014. Additionally, due to the significant decline in commodity prices, marginal wells have been temporarily shut in to control costs. LOE per Boe for the year ended December 31, 2015 was $10.58 compared to $12.39 for the same period of 2014. The decrease in LOE per Boe was attributable to higher sales volumes in 2015 as well as lower costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2015 decreased to $6.7 million from $11.5 million in 2014. The decrease was primarily due to significantly lower realized prices in 2015 as compared to 2014 which was partially offset by increased production in 2015 as compared to 2014. Production and ad valorem taxes as a percentage of oil and gas revenue increased to 10% in 2015 from 9% in 2014. The increase is due primarily to a higher production in the Rocky Mountain region that has a higher tax rate.

General and Administrative (“G&A”) Expense. G&A expense, excluding stock-based compensation, decreased to $7.9 million for the year ended December 31, 2015 from $10.7 million in 2014. G&A expense per Boe was $3.61 for the year ended December 31, 2015 compared to $5.11 for the same period of 2014. The decrease in G&A was primarily due to performance bonuses in 2014 that did not occur in 2015. Additionally, as a result of the current price environment, emphasis has been placed on reducing cost.

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 for the year ended December 31, 2015 increased to $3.9 million from $2.7 million in 2014. The increase was due to the grant of a greater number of options in 2015 as compared to 2014.

Depreciation, Depletion, and Amortization (“DD&A”) Expenses. DD&A expense decreased to $38.7 million for the year ended December 31, 2015 from $43.1 million in 2014. DD&A decreased primarily due to decreased future development costs included in the 2015 reserve reports. DD&A per Boe for 2015 was $17.76 compared to $20.66 in 2014. The decrease in DD&A per BOE was due to lower future development cost in 2015 as compared to 2014.

Interest Expense. Interest expense increased to $3.9 million in 2015 from $2.6 million for 2014. The increase was primarily due to higher levels of debt during 2015 as compared to 2014.

Income Taxes. An income tax benefit was recognized in 2015 as the result of an overpayment of state income taxes in 2014 that was refunded in 2015, as well as a benefit of a capital loss carryback which resulted in a refund of prior year federal taxes of $242,000

Loss (Gain) on Derivative Contracts. Derivative 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. 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 three way collar contracts in 2015 and fixed price swaps in 2014. The net estimated value of our commodity derivative contracts was an asset of approximately $27.4 million as of December 31, 2015. 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, 2015, we recognized a gain on our derivative contracts of approximately $19.3 million, consisting of a gain of $9.5 million on closed contracts and a gain of $9.8 million on the mark to market valuation of open contracts. For the year-ended December 31, 2014, we incurred a gain of $25.2 million, consisting of a gain of $0.3 million on closed contracts and a gain of $24.9 million related to open contracts.

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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 flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2014 the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2015, the net capitalized cost of our oil and gas properties exceeded the present value of our estimated proved reserves, resulting in the recognition of an impairment of $128.6 million in 2015. 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 2015 which were $50.12 per Bbl for oil and $2.63 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

We expect to record an additional impairment of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month unweighted average oil and gas prices through March 1, 2016 of $46.04 per Bbl of oil and $ 2.48 per Mcf of gas being held constant for the trailing 12-month period we estimate that we will record a ceiling test write down on our existing assets of approximately $30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of $72.7 million for the remainder of the year ending December 31, 2016.

However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGLs for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such im