US ENERGY CORP
Form 10-K
April 17, 2017

**UNITED STATES**

**SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

**FORM 10-K**

(Mark One)

þ **Annual report pursuant to section 13 or 15(d) of the SECURITIES EXCHANGE ACT OF 1934**

**For the Fiscal Year Ended December 31, 2016**

¨ **Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission File Number 000-6814

**U.S. ENERGY CORP.**
(Exact Name of Company as Specified in its Charter)

| | |
|---|---|
| **Wyoming** | **83-0205516** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **4643 S. Ulster Street, Suite 970, Denver, Colorado** | **80237** |
| (Address of principal executive offices) | (Zip Code) |
| Registrant's telephone number, including area code: | **(303) 993-3200** |

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Name of exchange on which registered |
|---|---|

**Common Stock, $0.01 par value   NASDAQ Capital Market**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ¨ NO þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ¨ NO þ

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 Company was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES þ NO ¨

Indicate by check mark whether 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 þ NO ¨

Indicate by check mark if disclosure of delinquent filers, pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ¨

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

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES ¨ NO þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant, based upon the closing price of the shares of common stock on the NASDAQ Capital Market as of the last business day of the most recently completed second fiscal quarter, June 30, 2016, was $8,108,271.

The Registrant had 6,134,506 shares of its $0.01 par value common stock outstanding as of  April 14, 2017.

The Registrant had 6,134,506 shares of its $0.01 par value common stock outstanding as of April 14, 2017.

Documents incorporated by reference: Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2017 annual meeting of stockholders to be filed within 120 days after December 31, 2016.

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**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS**

The information discussed in this Annual Report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). All statements other than statements of historical facts are forward-looking statements.

Examples of forward-looking statements in this Annual Report include:

- planned capital expenditures for oil and gas exploration and environmental compliance;
- potential drilling locations and available spacing units, and possible changes in spacing rules;
- cash expected to be available for capital expenditures and to satisfy other obligations;
- recovered volumes and values of oil and gas approximating third-party estimates;
- anticipated changes in oil and gas production;
- drilling and completion activities and opportunities in the Buda, Eagle Ford and other formations in South Texas, the Williston Basin in North Dakota and other areas;
- timing of drilling additional wells and performing other exploration and development projects;
- expected spacing and the number of wells to be drilled with our oil and gas industry partners;
- when payout-based milestones or similar thresholds will be reached for the purposes of our agreements with Statoil, Zavanna and other partners;
- expected working and net revenue interests, and costs of wells, relating to the drilling programs with our partners;
- actual decline rates for producing wells in the Buda, Bakken/Three Forks, Eagle Ford and other formations;
- future cash flows, expenses and borrowings;
- pursuit of potential acquisition opportunities;
- our expected financial position;
- our expected future overhead reductions;

- our ability to become an operator of oil and gas properties;
- our ability to raise additional financing and acquire attractive oil and gas properties; and
- other plans and objectives for future operations.

These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could,” “up to,” ar and phrases. Though we believe that the expectations reflected in these statements are reasonable, they involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of numerous factors, including, among others:

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;
- volatility in oil and gas prices, including further declines in oil prices and/or natural gas prices, which would have a negative impact on operating cash flow and could require further ceiling test write-downs on our oil and gas assets;
- the possibility that the oil and gas industry may be subject to new adverse regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);
- the general risks of exploration and development activities, including the failure to find oil and gas in sufficient commercial quantities to provide a reasonable return on investment;
- future oil and gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and gas reserves as they deplete from production;
- environmental risks;
- risks associated with our plan to develop additional operating capabilities, including the potential inability to recruit and retain personnel with the requisite skills and experience and liabilities we could assume or incur as an operator or to acquire operated properties or obtain operatorship of existing properties;
- availability of pipeline capacity and other means of transporting crude oil and gas production, and related midstream infrastructure and services;
- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms or fewer opportunities being available;

- higher drilling and completion costs related to competition for drilling and completion services and shortages of labor and materials;
- unanticipated weather events resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues; and
- unanticipated down-hole mechanical problems, which could result in higher than expected drilling and completion expenses and/or the loss of the wellbore or a portion thereof.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in Item 1A “Risk Factors” in this Annual Report on Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements made above and elsewhere in this Annual Report on Form 10-K. We do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations, or otherwise.

**Glossary of Oil and Gas Terms**

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X.

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

*Bcfe.* One billion cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

*BOE.* A barrel of oil equivalent is determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquid.

*Completion.* The installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned. Completion of the well does not necessarily mean the well will be profitable.

*Developed Acreage.* The number of acres which are allocated or assignable to producing wells or wells capable of production.

*Development Well.* A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

*Dry Well.* A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

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

*Gross Acres or Gross Wells.* The total acres or wells, as the case may be, in which we have a working interest.

*Lease Operating Expenses.* The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

*Mcf.* One thousand cubic feet of natural gas.

*Mcfe.* One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

*MMBtu.* One million Btu, or British Thermal Units. One British Thermal Unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

*Net Acres or Net Wells.* Gross acres or wells multiplied, in each case, by the percentage working interest we own.

*Net Production.* Production that we own less royalties and production due others.

*Oil.* Crude oil, condensate or other liquid hydrocarbons.

*Operator.* The individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

*Pay.* The vertical thickness of an oil and gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

*PV-10.* The pre-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

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

*Proved Reserves.* The estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

*Proved Undeveloped Reserves.* Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

*Royalty.* An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

*Standardized Measure.* The after-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

*Working Interest.* An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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# PART I

## Item 1 – Business

### Overview

U.S. Energy Corp. ("U.S. Energy", the "Company", "we" or "us"), is a Wyoming corporation organized in 1966. We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States. Our business activities are currently focused in South Texas and the Williston Basin in North Dakota. However, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

We have historically explored for and produced oil and gas through a non-operator business model. As a non-operator, we rely on our operating partners to propose, permit, drill, complete and produce oil and gas wells. Before a well is drilled, the operator provides all oil and gas interest owners in the designated well the opportunity to participate in the drilling and completion costs and revenues of the well on a pro-rata basis. Our operating partners also produce, transport, market and account for all oil and gas production. We are currently developing our capability to operate properties.

We believe that additional value can be generated if we have the ability to operate oil and gas properties because operatorship will allow us to control drilling and production timing, capital costs and future planning of operations. We plan to look for opportunities to operate our own wells in the near future through acquisition of new oil and gas properties and/or by consolidating ownership in and around the areas in which we currently participate. We believe the current price climate will make opportunities available for us to acquire and/or develop operated properties, and our objective is to eventually operate the properties which comprise the majority of our production.

### Office Location and Website

Our principal executive office is located at 4643 S. Ulster Street, Suite 970, Denver, Colorado 80237, telephone (303) 993-3200.

Our website is www.usnrg.com. We make available on this website, through a direct link to the Securities and Exchange Commission's (the "SEC") website at http://www.sec.gov, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and Forms 3, 4 and 5 relating to stock ownership of our directors, executive officers and significant shareholders. You may also find information related to our corporate governance, board committees and code of ethics on our website. Our website and the information contained on or connected to our website are not incorporated by reference herein and should not be considered part of this document. In addition, you may read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

**Oil and Gas Operations**

We currently participate in oil and gas projects as a non-operating working interest owner through exploration and development agreements with various oil and gas exploration and production companies. Our working interest varies by project and may change over time based on the terms of our leases and operating agreements. These projects may result in numerous wells being drilled over the next three to five years depending on, among other things, commodity prices and the availability of capital resources required to fund the expenditures. We are also actively pursuing potential acquisitions of exploration, development and production-stage oil and gas properties or companies. Key attributes of our oil and gas properties include the following:

- Estimated proved reserves of 887,142 BOE (74% oil and 26% natural gas) as of December 31, 2016, with a standardized measure value of $6.7 million.
- As of March 27, 2017, our oil and gas leases covered 95,839 gross and 7,958 net acres.
- 151 gross (20.94 net) producing wells as of December 31, 2016 and as of March 27, 2017.

· 581 BOE per day average net production for 2016.

PV-10 (defined in "Glossary of Oil and Gas Terms") is a non-GAAP measure that is widely used in the oil and gas industry and is considered by institutional investors and professional analysts when comparing companies. However, PV-10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under GAAP and includes the effects of income taxes. The following table reconciles the standardized measure of discounted future net cash flows to PV-10 as of December 31, 2016, 2015 and 2014:

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Standardized measure of discounted net cash flows | $6,747 | $17,768 | $81,889 |
| Plus discounted impact of future income tax expense | - | - | 3,307 |
| PV-10 | $6,747 | $17,768 | $85,196 |

Additional information about our standardized measure and the changes during each of the last three years is included in Note 17 to our consolidated financial statements included in Item 8 of this report on Form 10-K.

**Activities with Operating Partners**

The Company owns working interests in a geographically and geologically diverse portfolio of oil-weighted prospects in varying stages of exploration and development. Prospect stages range from prospect origination, including geologic and geophysical mapping, to leasing, exploratory drilling and development. The Company participates in the prospect stages either for its own account or with prospective partners to enlarge its oil and gas lease ownership base.

Each of the operators of our principal prospects has a substantial technical staff. We believe that these arrangements currently allow us to deliver value to our shareholders without having to build the full staff of geologists, engineers and land personnel required to work on diverse projects involving horizontal drilling in North Dakota and South Texas and conventional exploration in our Gulf Coast prospects. However, consistent with industry practice with smaller independent oil and gas companies, we also utilize specialized consultants with local expertise as needed. We anticipate that as we establish an operational center in an area, we will hire appropriate resources to supply critical aspects of the operations, such as drilling, completions and production.

Presented below is a description of key oil and gas projects with our operating partners:

**Williston Basin, North Dakota (Bakken and Three Forks Formations)**

***Statoil ASA.*** On August 24, 2009, we entered into a Drilling Participation Agreement (the “DPA”) with a wholly-owned subsidiary of Brigham Exploration Company (“Brigham”) to jointly explore for oil and gas in up to 19,200 gross acres in a portion of Brigham’s Rough Rider prospect in Williams and McKenzie Counties, North Dakota. Brigham was subsequently acquired by Statoil ASA. As part of the program we have participated in 26 wells and have proven up additional drilling locations depending on the successful development of the Three Forks Formation. These properties currently operated by Statoil comprise approximately 22% of the PV-10 related to our oil and gas reserves. Currently development has stopped due to the commodity price drop and high costs. We expect to develop the remaining acreage in the future when economics allow an acceptable return on capital.

The leases in the units are a combination of fee and state leases and all are held by production. In some areas, the rights may be depth limited to the Bakken and the upper part of the Three Fork formations under the terms of the leases obtained by Brigham from third parties, while other leases may have rights to all depths. Working interests earned vary according to Brigham’s interest.

***Zavanna, LLC.*** In December 2010, we signed two agreements with Zavanna, LLC (“Zavanna”) and other parties whereby we acquired 35% of Zavanna’s working interests in oil and gas leases covering approximately 6,200 net acres in McKenzie County, North Dakota. The total net acres subject to the agreement has increased to 6,500 as a result of subsequent acquisitions from third parties. The acquired acreage is in two prospects – the Yellowstone Prospect and the SE HR Prospect. We expect this program will ultimately result in 27 gross 1,280-acre spacing units with the potential for 108 gross Bakken and 108 gross Three Forks wells, based on an assumed four wells per formation in each spacing unit.

Effective December 2011, we sold an undivided 75% interest of our undeveloped acreage in the SE HR Prospect and the Yellowstone Prospect to GeoResources, Inc. and Yuma Exploration and Production Company, Inc. Under the terms of the agreement, we retained the remaining 25% interest in the undeveloped acreage and our original working interest in 10 completed wells in the SE HR and Yellowstone prospects. Our working interest in the remaining locations will be approximately 8.75% and net revenue interests in new wells after the sale are expected to be in the range of 6.7% to 7.0%, proportionately reduced depending on Zavanna’s actual working interest percentages. These properties operated by Zavanna currently comprise approximately 28% of the PV-10 related to our oil and gas reserves.

**Texas and Louisiana (Gulf Coast)**

***Contango Oil and Gas Company (Eagle Ford Shale).*** In February 2011, we entered into a participation agreement with Crimson Exploration Inc. (“Crimson”) to acquire a 30% working interest in an oil prospect and associated leases located in Zavala County, Texas (the “Leona River prospect”). Crimson was subsequently acquired by Contango Oil and Gas Company (“Contango”) in 2013. Under the terms of the agreement, we earned a 30% working interest (22.5% net revenue interest) in approximately 4,675 gross contiguous acres (1,402 net mineral acres) through a combination of a cash payment and commitment well carry. All future drilling and leasing will be on a heads up basis, meaning working interest participants are responsible for their own pro-rata share of costs. The prospect is an Eagle Ford shale oil window target in Zavala County, Texas. Two wells were drilled by Crimson to a total depth of approximately 12,500 feet (approximately 6,000 feet vertical and 6,500 feet horizontal) at the Leona River prospect. These producing wells hold the remaining development acreage.

In June 2011, we entered into a second participation agreement with Crimson to acquire an interest in an Eagle Ford oil prospect and associated leases located in Zavala and Dimmit Counties, Texas (the “Booth Tortuga prospect”). Under the terms of this second agreement with Crimson, we have acquired 30% of Crimson’s working interest (approximately 22.5% net revenue interest) in approximately 7,186 gross acres (2,156 net).

Contango is currently the operator of the Leona River and Booth Tortuga prospects. All of the leases are currently held by production and comprise approximately 9% of the PV-10 related to our oil and gas reserves. Currently, our total acreage in the Leona River prospect and the Booth Tortuga prospect is approximately 11,861 gross acres (3,558 net). Based upon expected 120-acre spacing units, there is the potential for up to 98 gross and 30 net Eagle Ford drilling locations.

***PetroQuest Energy, Inc.*** We have an interest in three natural gas and oil producing wells with PetroQuest Energy, Inc. ("PetroQuest") in Coastal Louisiana, with working interests of 11.9% (8.3% net revenue interest), 50.0% (36.0% net revenue interest) and 17.0% (12.75% net revenue interest). Petro-Quest operates the wells. These properties operated by PetroQuest currently comprise approximately 17% of the PV-10 related to our oil and gas reserves.

**Environmental Laws and Regulations**

For additional information regarding applicable environmental laws and regulations, see *Oil and gas operations are subject to environmental and other regulations that can materially adversely affect the timing and cost of operations*; *Hazardous Substances and Waste*; *Air Emissions; Discharges into Waters*; *Health and Safety*; *Endangered Species*; and *Global Warming and Climate Change* in Item 1A Risk Factors in this Form 10-K.

*Environmental Matters*

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may:

- Require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;

- Limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and

- Impose substantial liabilities for pollution resulting from its operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act (“CERCLA”) and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of “hazardous substances” found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes govern the disposal of “solid waste” and “hazardous waste” and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of “hazardous substance,” state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as “non-hazardous,” such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. Recent regulation and litigation that has been brought against others in the industry under RCRA concern liability for earthquakes that were allegedly caused by injection of oil field wastes.

The Endangered Species Act (“ESA”) seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of ESA. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations are in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our operating partners) to significant expenses to modify our operations or could force discontinuation of certain operations altogether.

On April 17, 2012, the U.S. Environmental Protection Agency (the "EPA") finalized rules proposed on July 28, 2011 that establish new air emission controls under the Clean Air Act ("CCA") for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards ("NSPS") for the oil and natural gas source category to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. On August 5, 2013, the EPA issued final updates to its 2012 VOC performance standards for storage tanks. The rules establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules revise leak detection requirements for natural gas processing plants. These rules have required a number of modifications to the operations of our third-party operating partners, including the installation of new equipment to control emissions from compressors.

We are subject to the federal authority of the U.S. Environmental Protection Agency (the “EPA”) and its promulgated rules specifically as they pertain to the Clean Air Act (“CCA”). Applicable to our business and operations, the CCA regulates the emissions, discharges and controls of oil and natural gas production and natural gas processing operations. The CCA includes New Source Performance Standards (“NSPS”) for the oil and natural gas source category to address emissions of sulfur dioxide, methane and volatile organic compounds (“VOCs”) from new and modified oil and gas production, processing and transmission sources as well as a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. Further, the CCA regulates the emissions from compressors, dehydrators, storage tanks and other production equipment as well as leak detection for natural gas processing plants. Although we cannot predict the cost to comply with current and future rules and regulations at this point, compliance with applicable rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

The current and future rules, regulations and proposals requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations and financial condition.

The federal Water Pollution Control Act of 1972, or the Clean Water Act (the “CWA”), imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. 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 natural resource damages resulting from the release.

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. 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. Substantially all of the oil and natural gas production in which we have interests is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate oil and gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act to address hydraulic fracturing operations.

Scrutiny of hydraulic fracturing activities continues in other ways. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. Several states, including North Dakota where many of our properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have enacted bans on hydraulic fracturing. New York State's ban on hydraulic fracturing was recently upheld by the Courts. In Colorado, the Colorado Supreme Court has ruled the municipal bans were preempted by state law. We cannot predict whether any other legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, which could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our revenue and results of operations.

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA. Many of the activities of our third-party operating partners are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews which may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

*Climate Change*

Significant studies and research have been devoted to climate change, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production.

In the United States, legislative and regulatory initiatives are underway to limit greenhouse gas ("GHG") emissions. The U.S. Congress has considered legislation that would control GHG emissions through a "cap and trade" program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act, or the CAA, definition of an "air pollutant." In response the EPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. In 2010, the EPA issued a final rule, known as the "Tailoring Rule," that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act. A previous United States Supreme Court case held that the EPA's "Tailoring Rule" was invalid, but held that if a source was subject to Prevention of Significant Deterioration ("PSD") or Title V based on emissions of conventional pollutants like sulfur dioxide, particulates, nitrogen dioxide, carbon monoxide, ozone or lead, then the EPA could also require the source to control GHG emissions and the source would have to install Best Available Control Technology to do so. As a result, a source no longer is required to meet PSD and Title V permitting requirements based solely on its GHG emissions, but may still have to control GHG emissions if it is an otherwise regulated source.

Colorado became the first state in the nation to adopt rules to control methane emissions from oil and gas facilities. On June 3, 2016, the EPA issued three final rules that were intended to curb emissions of methane, VOCs and toxic air pollutants such as benzene from new, reconstructed and modified oil and gas sources. These new regulations include leak detection and repair provisions, and may require controls to reduce methane emissions from certain oil and gas facilities. To the extent our third party operating partners are required to further control methane emissions, such controls could impact our business.

Certain EPA rules require the reporting of GHGs from specified large GHG emission sources in the United States and have expanded existing GHG emissions reporting to include onshore and offshore oil and natural gas systems. Our third-party operating partners are required to report their greenhouse gas emissions under these rules. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Moreover, there is some litigation risk for tort claims against sources of GHG emissions alleging property damage under state common law. Although we cannot predict the cost to comply with current and future rules and regulations at this point, compliance with applicable rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous.  Although operators may take steps to mitigate physical risks from storms, no assurance can be given that future storms will not have a material adverse effect on our business.

**Research and Development**

No research and development expenditures have been incurred, either on the Company's account or sponsored by a customer of the Company, during the past three fiscal years.

**Insurance and Employees**

The following summarizes the material aspects of the Company's insurance coverage:

*General*

We have liability insurance coverage in amounts we deem sufficient for our business operations, consisting of property loss insurance on all major assets equal to the approximate replacement value of the assets and additional liability and control of well insurance for our oil and gas drilling programs. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in curtailment of projected future operations.

*Mt. Emmons Project*

The Company was responsible for all costs to operate the water treatment plant at the Mt. Emmons Project until the disposition of this property in February 2016. During 2016 and 2017, we have continued to maintain $10 million of coverage for environmental impairment liability.

**Employees**

As of December 31, 2016, we had 2 total and full-time employees and we utilized several consultants on an as needed basis.

**Forward Plan**

In 2017 and beyond, we intend to seek additional opportunities in the oil and gas sector, including but not limited to further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and the purchase and exploration of new acreage positions.

**Business Strategy**

Key elements of our business strategies include:

- *Deploy our Capital in a Conservative and Strategic Manner and Review Opportunities to Bolster our Liquidity*. In the current industry environment, maintaining liquidity is critical. Therefore, we will be highly selective in the projects we evaluate and will review opportunities to bolster our liquidity and financial position through various means.

- *Evaluate and Pursue Value-Enhancing Transactions*. We will continue to monitor the market for strategic alternatives that we believe could enhance shareholder value.

- *Continue to Develop Operating Capabilities*. We will continue to seek transactions where we can gain operational control of any potential development activities. We seek to gain operatorship to retain more control over the timing, selection and processes which will enhance our ability to maximize our return on invested capital.

**Industry Operating Environment**

The oil and natural gas industry is affected by many factors that we generally cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on operations and profitability. Significant factors that will impact oil prices in the current fiscal year and future periods include: political and social developments in the Middle East, demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Additionally, natural gas prices continue to be under pressure due to concerns over excess supply of natural gas due to the high productivity of emerging shale plays in the United States. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

Oil and natural gas prices have fallen significantly since their early third quarter 2014 levels and NYMEX WTI oil prices dropped to the $26 per Bbl level in February 2016. Although oil prices have increased since February 2016, they remain well below the $100 per Bbl oil prices realized during 2014. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders.

**Development**

We primarily engage in oil and natural gas exploration and production by participating, on a proportionate basis, alongside third-party interests in wells drilled and completed in spacing units that include our acreage. In addition, from time-to-time, we acquire working interests in wells in which we do not hold the underlying leasehold interests from third parties unable or unwilling to participate in particular well proposals. We typically depend on drilling partners to propose, permit and initiate the drilling of wells. Prior to commencing drilling, our partners are required to provide all owners of oil, natural gas and mineral interests within the designated spacing unit the opportunity to participate in the drilling costs and revenues of the well to the extent of their pro-rata share of such interest within the spacing unit. We assess each drilling opportunity on a case-by-case basis and participate in wells that we expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and natural gas, expected oil and gas prices, expertise of the operator, and completed well cost from each project, as well as other factors. Historically, we have participated pursuant to our working interest in a vast majority of the wells proposed to us. However, the recent significant decline in oil prices has reduced both the number of well proposals we receive and the proportion of well proposals in which we have elected to participate.

**Competition**

The oil and natural gas industry is intensely competitive, and we compete with numerous other oil and natural gas exploration and production companies.  Some of these companies have substantially greater resources than we have. Not only do they explore for and produce oil and natural gas, but also many carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis.  The operations of other companies may be able to pay more for exploratory prospects and productive oil and natural gas properties. They may also have more resources to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Our larger or integrated competitors may be better able to absorb the burden of existing and future federal, state, and local laws and regulations than we can, which would adversely affect our competitive position.  Our ability to discover reserves and acquire additional properties in the future will be dependent upon our ability and resources to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.  In addition, we may be at a disadvantage in producing oil and natural gas properties and bidding for exploratory prospects because we have fewer financial and human resources than other companies in our industry.  Should a larger and better financed company decide to directly compete with us, and be successful in its efforts, our business could be adversely affected.

**Marketing and Customers**

The market for oil and natural gas that will be produced from our properties depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners include a concentrated list of exploration and production companies, from large publicly-traded companies to small, privately-owned companies. We believe the loss of one of our major operators would have a material adverse effect on our company as a whole.

**Seasonality**

Winter weather conditions and lease stipulations can limit or temporarily halt the drilling and producing activities of our operating partners and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt the operations of our operating partners and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operating partners' operations.

**Governmental Regulation**

Our operations are subject to various rules, regulations and limitations impacting the oil and natural gas exploration and production industry as whole.

*Regulation of Oil and Natural Gas Production*

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, North Dakota require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. Many states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (“FERC”) and the courts. We cannot predict when or whether any such proposals may become effective.

*Regulation of Transportation of Oil*

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The 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, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. On December 17, 2015, the FERC established a new price index for the five-year period which commenced on July 1, 2016.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, 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 our operations in any way that is of material difference from those of our competitors who are similarly situated.

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 similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by pro-rationing 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 similarly situated competitors.

*Regulation of Transportation and Sales of Natural Gas*

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Onshore gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states.  Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

**Mining Activities**

As discussed in Note 6 to the audited financial statements included in Item 8 of this report on Form 10-K and *Management's Discussion and Analysis of Financial Condition and Results of Operations* included in Item 7 of this report on Form 10-K, in February 2016 we disposed of our Mt. Emmons Project located near Crested Butte, Colorado rather than continuing our long-term development strategy. Accordingly, our mining assets and operations have been treated as discontinued operations as of December 31, 2016 and for all prior periods presented in our financial statements.

**Item 1A - Risk Factors**

*The following risk factors should be carefully considered in evaluating the information in this Annual Report.*

**Risks Involving Our Business**

***The development of oil and gas properties involves substantial risks that may result in a total loss of investment.***

The business of exploring for and developing natural gas and oil properties involves a high degree of business and financial risk, and thus a significant risk of loss of initial investment that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost and timing of drilling, completing and operating wells is often uncertain. Factors which can delay or prevent drilling or production, or otherwise impact expected results, include but are not limited to:

- unexpected drilling conditions;
- inability to obtain required permits from governmental authorities;
- inability to obtain, or limitations on, easements from land owners;
- uncertainty regarding our operating partners' drilling schedules;
- high pressure or irregularities in geologic formations;

- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution, spills and other environmental risks or accidents;
- changes in government regulations and issuance of local drilling restrictions or moratoria;
- adverse weather;
- reductions in commodity prices;
- pipeline ruptures; and
- unavailability or high cost of equipment, field services and labor.

A productive well may become uneconomic in the event that unusual quantities of water or other non-commercial substances are encountered in the well bore that impair or prevent production. We may participate in wells that are or become unproductive or, though productive, do not produce in economic quantities. In addition, even commercial wells can produce less, or have higher costs, than we projected.

In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not necessarily indicative of future production rates.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities can adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves. We do not currently operate any of our properties, and therefore have limited ability to control the manner in which drilling and other exploration and development activities on our properties are conducted, which may increase these risks. Conversely, our anticipated transition to an operated business model entails risks as well. For example, the benefits of this transition may be less, or the costs may be greater, than we currently anticipate. In addition, we may be subject to a greater risk of drilling dry holes or encountering other operational problems until our operating capabilities are more fully developed. Similarly, we may incur liabilities as an operator that we have historically avoided through a non-operated business model.

***Our business has been and may continue to be impacted by adverse commodity prices.***

For the three years ended December 31, 2016, oil prices have ranged from highs over $100 per barrel in mid-2014 to lows below $30 per barrel in 2016. Global markets, in reaction to general economic conditions and perceived impacts of future global supply, have caused large fluctuations in price, and we believe significant future price swings are likely. Natural gas prices and NGL prices have experienced declines of comparable magnitude since mid-2014. Declines in the prices we receive for our oil and gas production have and may continue to adversely affect many aspects of our business, including our financial condition, revenues, results of operations, cash flows, liquidity, reserves, rate of growth and the carrying value of our oil and gas properties, all of which depend primarily or in part upon those prices. The reduction in drilling activity will likely result in lower production and, together with lower realized oil prices, lower revenue and EBITDAX. Declines in the prices we receive for our oil and gas can also adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices can reduce the amount of oil and gas that we can produce economically and the estimated future cash flow from that production and, as a result, adversely affect the quantity and present value of our proved reserves. Among other things, a reduction in the amount or present value of our reserves can limit the capital available to us, and the availability of other sources of capital likely will be based to a significant degree on the estimated quantity and value of the reserves.

***The Williston Basin oil price differential could have adverse impacts on our revenue.***

Generally, crude oil produced from the Bakken formation in North Dakota is high quality (36 to 44 degrees API, which is comparable to West Texas Intermediate Crude). During 2016, our realized oil prices in the Williston Basin were approximately $6.00 per barrel less than West Texas Intermediate (“WTI”) quoted prices for crude oil. This discount, or differential, may widen in the future, which would reduce the price we receive for our production. We may also be adversely affected by widening differentials in other areas of operation.

Drilling and completion costs for the wells we drill in the Williston Basin are comparable to or higher than other areas where there is no price differential. This makes it more likely that a downturn in oil prices will result in a ceiling limitation write-down of our Williston Basin oil and gas properties. A widening of the differential would reduce the cash flow from our Williston Basin properties and adversely impact our ability to participate fully in drilling with Statoil, Zavanna and other operators and to effect our strategy of transitioning to an operated business model. Our production in other areas could also be affected by adverse changes in differentials. In addition, changes in differentials could make it more difficult for us to effectively hedge our exposure to changes in commodity prices.

***The agreement governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.***

The debt agreement between our wholly-owned subsidiary, Energy One LLC (“Energy One”), and Wells Fargo Bank, N.A. contains restrictive covenants that limit Energy One’s ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including covenants that require the (i) interest coverage ratio (EBITDAX to interest expense) to exceed 3.0 to 1.0; (ii) total debt to EBITDAX ratio to be less than 3.5 to 1; and (iii) the current ratio to exceed 1.0 to 1.0, each as defined in the Credit Facility. Our prior and continuing failure to comply with these covenants in the future has resulted in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient capital resources to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. Adverse commodity prices and reduced drilling activity may result in continuing breaches of the covenants in the Credit Facility. The ongoing availability of borrowings under this Credit Facility through the maturity date of July 30, 2017, or the receipt of funding from alternative sources, is critical to our ability to survive until oil and gas prices recover.

Additionally, the Credit Facility restricts Energy One’s ability to incur additional debt, pay cash dividends and other restricted payments, sell assets, enter into transactions with affiliates, and to merge or consolidate with another company. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

***We require funding for our working capital deficit and debt obligations. We may be unable to obtain such funding, particularly as we are in continuing breach of covenants in the Credit Facility.***

Our working capital at December 31, 2016 was negative $6.0 million which is primarily the result of classifying $6.0 million of borrowings under the Credit Facility with Wells Fargo as a current liability. During 2015 and 2016, we were unable to maintain compliance with certain financial ratio covenants in the Credit Facility with Wells Fargo. In April 2016, Wells Fargo provided a waiver for non-compliance with the covenants in the Credit Facility for the fiscal quarter ended December 31, 2015. In August 2016 Wells Fargo agreed to enter into a fourth amendment to the Credit Facility that provided for, among other things, a limited waiver of the negative financial covenants for the fiscal quarters ended March 31, 2016 and June 30, 2016. The Company violated the financial ratio covenants for the fiscal quarters ended September 30, 2016 and December 31, 2016, which constituted an event of default under the credit agreement. Accordingly, Wells Fargo has the immediate right to demand acceleration of all outstanding borrowings and has the ability to foreclose upon the existing collateral. Wells Fargo notified the Company that default rate interest is accruing on all outstanding balances under the Credit Facility. Even though this debt does not mature until July 2017, we have been unable to comply with the debt covenants during 2017 and we project continuing non-compliance. While Wells Fargo has historically provided waivers for our non-compliance, there is no assurance that it will continue to do so in the future. In addition, the borrowing base under the Credit Facility is subject to redetermination periodically and from time to time in the lenders' discretion. Borrowing base reductions may occur as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the Credit Facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time. Currently, we do not have adequate funding to repay Wells Fargo if it chooses to demand an accelerated repayment of the outstand borrowings or foreclose upon the existing collateral. The ongoing availability of borrowings under this Credit Facility through the maturity date of July 30, 2017, or the receipt of funding from alternative sources, is critical to the Company's ability to survive until oil and gas prices recover.

Regardless of our ability to comply with the covenants under the Credit Facility, we will pursue alternative funding sources before the facility matures in July 2017. Other sources of external debt or equity financing may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Also, the issuance of equity may be dilutive to existing shareholders. During 2017, we will attempt to obtain a larger credit facility that will enable the repayment of amounts outstanding under the Credit Facility and provide capital resources to participate in acquisition and development activities; obtaining additional financing is an important objective for us in 2017 and may be critical in our efforts to continue to operate and to avoid bankruptcy, liquidation or similar proceedings. We cannot provide any assurance that we will be successful in this regard.

Should we be unsuccessful in these efforts to refinance the Credit Facility, we may be forced to sell assets to raise sufficient capital to repay the Credit Facility by the maturity date of July 30, 2017. The sale of sufficient assets to repay the Credit Facility in full would likely include substantially all of the Company's income-producing properties, resulting, in effect, in the liquidation of the Company.

Our industry partners may elect to engage in drilling activities that we are unwilling or unable to participate in during 2017. Our exploration and development agreements contain customary industry non-consent provisions. Pursuant to these provisions, if a well is proposed to be drilled or completed but a working interest owner elects not to participate, the resulting revenues (which otherwise would go to the non-participant) flow to the participants until they receive from 150% to 300% of the capital they provided to cover the non-participant's share. In order to be in position to avoid non-consent penalties and to make opportunistic investments in new assets, we will continue to evaluate various options to obtain additional capital, including additional debt financing, sales of one or more producing or non-producing oil and gas assets and the issuance of shares of our common stock.

The oil and gas business presents the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. For example, initial results from one or more of the oil and gas programs could be marginal but warrant investing in more wells. Dry holes, over-budget exploration costs, low commodity prices, or any combination of these or other adverse factors, could result in production revenues below projections, thus adversely impacting cash expected to be available for continued work in a program, and a reduction in cash available for investment in other programs. These types of events could require a reassessment of priorities and therefore potential re-allocations of existing capital and could also mandate obtaining new capital. There can be no assurance that we will be able to complete any financing transaction on acceptable terms.

***We may be unable to continue as a going concern.***

We have substantial debt obligations and our ongoing capital and operating expenditures will exceed the revenue we expect to receive from our oil and natural gas operations in the near future. If we are unable to raise substantial additional funding, refinance existing indebtedness or consummate significant asset sales on a timely basis and/or on acceptable terms, we may be required to significantly curtail our business and operations.

The consolidated financial statements included in this report on Form 10-K have been prepared on a going concern basis of accounting, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The consolidated financial statements do not reflect any adjustments that might be necessary should we be unable to continue as a going concern. Our ability to continue as a going concern is subject to, among other factors, our ability to monetize assets, our ability to obtain financing or refinance existing indebtedness, our ability to continue our cost cutting efforts, oil and gas commodity prices, our ability to recognize, acquire and develop strategic interests and prospects, the speed and cost with which we can develop our prospects and the ability to adapt our business by integrating specific operations associated with operating companies. There can be no assurance that we will be able to obtain additional funding on a timely basis and on satisfactory terms, or at all. In addition, no assurance can be given that any such funding, if obtained, will be adequate to meet our capital needs and support our growth. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then our operations would be materially negatively impacted and we may be unable to continue as a going concern. If we become unable to continue as a going concern, we may find it necessary to file a voluntary petition for reorganization under the Bankruptcy Code in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure. For additional information, please see Items 7 and 8 contained in this report on Form 10-K.

***Competition may limit our opportunities in the oil and gas business.***

The oil and gas business is very competitive. We compete with many public and private exploration and development companies in finding investment opportunities. We also compete with oil and gas operators in acquiring acreage positions. Our principal competitors are small to mid-size companies with in-house petroleum exploration and drilling expertise. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. They also may be willing and able to pay more for oil and gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. In addition, there is substantial competition in the oil and gas industry for investment capital, and we may not be able to compete successfully in raising additional capital if needed.

***Successful exploitation of the Buda formation, the Williston Basin (Bakken and Three Forks shales) and the Eagle Ford shale is subject to risks related to horizontal drilling and completion techniques.***

Operations in the Buda formation and the Bakken, Three Forks and Eagle Ford shales in many cases involve utilizing the latest drilling and completion techniques in an effort to generate the highest possible cumulative recoveries and therefore generate the highest possible returns. Risks that are encountered while drilling include, but are not limited to, landing the well bore in the desired drilling zone, staying in the zone while drilling horizontally through the shale formation, running casing the entire length of the well bore (as applicable to the formation) and being able to run tools and other equipment consistently through the horizontal well bore.

For wells that are hydraulically fractured, completion risks include, but are not limited to, being able to fracture stimulate the planned number of frac stages, and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these latest drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficient period of time.

Costs for any individual well will vary due to a variety of factors. These wells are significantly more expensive than a typical onshore shallow conventional well. Accordingly, unsuccessful exploration or development activity affecting even a small number of wells could have a significant impact on our results of operations. Costs other than drilling and completion costs can also be significant for Williston Basin, Eagle Ford and other wells.

***If our access to oil and gas markets is restricted, it could negatively impact our production and revenues. Securing access to takeaway capacity may be particularly difficult in less developed areas of the Williston Basin.***

Market conditions or limited availability of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines and other midstream facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, rail transportation and processing facilities owned and operated by third parties. In particular, access to adequate gathering systems or pipeline or rail takeaway capacity is limited in the Williston Basin. In order to secure takeaway capacity and related services, we or our operating partners may be forced to enter into arrangements that are not as favorable to operators as those in other areas.

***If we are unable to replace reserves, we will not be able to sustain production.***

Our future operations depend on our ability to find, develop, or acquire crude oil, natural gas, and NGL reserves that are economically producible. Our properties produce crude oil, natural gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new crude oil, natural gas, and NGL reserves to replace those being depleted by production. Without successful drilling or acquisition activities, our reserves and production will decline over time. In addition, competition for crude oil and gas properties is intense, and many of our competitors have financial, technical, human, and other resources necessary to evaluate and integrate acquisitions that are substantially greater than those available to us.

As part of our growth strategy, we have made and may continue to make acquisitions. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources than we do. In the event we do complete an acquisition, its successful impact on our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price for the acquisition, future crude oil, natural gas, and NGL prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation, and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited. If we are unable to integrate acquisitions successfully and realize anticipated economic, operational and other benefits in a timely manner, substantial costs and delays or other operational, technical or financial problems could result.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

***Lower oil and gas prices may cause us to record ceiling test write-downs.***

We use the full cost method of accounting to account for our oil and gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop these properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a “ceiling limit” that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs exceed the ceiling limit, we must charge the amount of the excess to earnings (a charge referred to as a “ceiling test write-down”). The risk of a ceiling test write-down increases when oil and gas prices are depressed, if we have substantial downward revisions in estimated proved reserves or if we drill unproductive wells.

Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost, except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depreciation, depletion and amortization are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of (a) unamortized cost reduced by the related net deferred tax liability and asset retirement obligations, and (b) the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated costs, adjusted for contract provisions, any financial derivatives that hedge our oil and gas revenue and asset retirement obligations, and unescalated oil and gas prices during the period, (ii) the cost of properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, less (iv) income tax effects related to tax assets directly attributable to the natural gas and crude oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs.

We perform a quarterly ceiling test for our only oil and gas cost center, which is the United States. During 2016, capitalized costs for oil and gas properties exceeded the ceiling and we recorded aggregate ceiling test write-downs of $9.6 million primarily due to a decline in the prices of oil and gas. The ceiling test incorporates assumptions regarding pricing and discount rates over which we have no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2016, we used a weighted average price applicable to our properties of $42.75 per barrel for oil and $2.48 per Mcfe for natural gas to compute the future cash flows of each of the producing properties at that date.

Capitalized costs associated with unevaluated properties include exploratory wells in progress, costs for seismic analysis of exploratory drilling locations, and leasehold costs related to unproved properties. Unevaluated properties not subject to depreciation, depletion and amortization amounted to an aggregate of $4.7 million as of December 31, 2016. These costs will be transferred to evaluated properties to the extent that we subsequently determine the properties are impaired or if proved reserves are established.

***We do not currently serve as operator for any of our oil and gas properties. Many of our joint operating agreements contain provisions that may be subject to legal interpretation, including allocation of non-consent interests, complex payout calculations that impact the timing of reversionary interests, and the impact of joint interest audits.***

Substantially all of our oil and gas interests are subject to joint operating and similar agreements. Some of these agreements include payment provisions that are complex and subject to different interpretations and/or can be erroneously applied in particular situations. In the past, we received significant overpayments due to an operator's failure to timely recognize the payout implications of our joint operating agreements. The operator has elected to withhold the net revenues from all of our wells that it operates to recover these overpayments, decreasing cash flows that would otherwise be available to operate our business.

We believe certain operators have failed to allocate our share of non-consent ownership interests which results in contingent liabilities to the extent we have not been billed for our proportionate share of such interests, and contingent assets to the extent that we have not received our share of the net revenues. We record net contingent liabilities for the obligations that we believe are probable. Additionally, we believe an operator has failed to allocate our share of certain royalty interests that we are entitled to under a participation agreement. The ultimate resolution of these uncertainties about our working interests and net revenue interests can extend over a long period of time and we can incur substantial amounts of legal fees to resolve disputes with the operators of our properties.

Joint interest audits are a normal process in our business to ensure that operators adhere to standard industry practices in the billing of costs and expenses related to our oil and gas properties. However, the ultimate resolution of joint interest audits can extend over a long period of time in which we attempt to recover excessive amounts charged by the operator. Joint interest audits result in incremental costs for the audit services and we can incur substantial amounts of legal fees to resolve disputes with the operators of our properties.

***We do not currently operate our drilling locations. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of these non-operated assets.***

We do not currently operate any of the prospects we hold with industry partners. As a non-operator, our ability to exercise influence over the operations of the drilling programs is limited. In the usual case in the oil and gas industry, new work is proposed by the operator and often is approved by most of the non-operating parties. If the work is approved by the holders of a majority of the working interests, but we disagree with the proposal and do not (or are unable to) participate, we will forfeit our share of revenues from the well until the participants receive 150% to 300% of their investment. In some cases, we could lose all of our interest in the well. We would avoid a penalty of this kind only if a majority of the working interest owners agree with us and the proposal does not proceed.

The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- the nature and timing of the operator’s drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator’s geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator’s selection of suitable technology.

The fact that our industry partners serve as operator makes it more difficult for us to predict future production, cash flows and liquidity needs. Our ability to grow our production and reserves depends on decisions by our partners to drill wells in which we have an interest, and they may elect to reduce or suspend the drilling of those wells.

***Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.***

Oil and gas reserve reports are prepared by independent consultants to provide estimates of the quantities of hydrocarbons that can be economically recovered from proved properties, utilizing commodity prices for a trailing 12-month period and taking into account expected capital, operating and other expenditures. These reports also provide estimates of the future net present value of the reserves, which we use for internal planning purposes and for testing the carrying value of the properties on our balance sheet.

The reserve data included in this report represent estimates only. Estimating quantities of, and future cash flows from, proved oil and gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future production costs; ad valorem, severance and excise taxes; availability of capital; estimates of required capital expenditures, workover and remedial costs; and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of the reserves, the economically recoverable quantities of oil and gas attributable to the properties, the classifications of reserves based on risk of recovery, and estimates of our future net cash flows.

At December 31, 2016, 99% of our estimated proved reserves were producing and 1% were proved developed non-producing. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, volumetric analysis or probabilistic methods, in contrast to the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenue from estimated proved developed non-producing and proved undeveloped reserves will not be realized until sometime in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and gas reserves. The timing and success of the production and the expenses related to the development of oil and gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV-10 and standardized measure estimates are based on costs as of the date of the estimates and assume fixed commodity prices. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

Further, the use of a 10% discount factor to calculate PV-10 and standardized measure values may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and gas industry in general are subject.

***The use of derivative arrangements in oil and gas production could result in financial losses or reduce income.***

From time to time, we use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil production. The fair value of our derivative instruments is marked to market at the end of each quarter and the resulting unrealized gains or losses due to changes in the fair value of our derivative instruments is recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for the relevant period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counter-party to the derivative instrument defaults on its contract obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- the steps we take to monitor our derivative financial instruments do not detect and prevent transactions that are inconsistent with our risk management strategies.

In addition, depending on the type of derivative arrangements we enter into, the agreements could limit the benefit we would receive from increases in oil prices. It cannot be assumed that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in commodity prices.

Additionally, the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through regulations that either have been or are in the process of being implemented by the SEC, the Commodities Futures Trading Commission and other regulators. If, as a result of the Dodd-Frank Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions (which are currently not collateralized unless our counterparty’s exposure reaches a certain level) would likely make it impracticable to implement our current hedging strategy. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy.

***Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, the loss of our lease and prospective drilling opportunities.***

Unless production is established within the spacing units covering the undeveloped acres on which some of our potential drilling locations are identified, the leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. The risk that our leases may expire will generally increase when commodity prices fall, as lower prices may cause our operating partners to reduce the number of wells they drill. In addition, on certain portions of our acreage, third-party leases could become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

***Our producing properties are primarily located in the Williston Basin and South Texas, making us vulnerable to risks associated with having operations concentrated in these geographic areas.***

Because our operations are geographically concentrated in the Williston Basin and South Texas, the success and profitability of our operations may be disproportionally exposed to the effect of regional events. These include, among others, regulatory issues, natural disasters and fluctuations in the prices of crude oil and gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and other transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. Any of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. In addition, our operations in the Williston Basin may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, which can intensify competition for services, infrastructure and equipment during months when drilling is possible and may result in periodic shortages. Any of these risks could have a material adverse effect on our financial condition and results of operations.

***Insurance may be insufficient to cover future liabilities.***

Our business is currently focused on oil and gas exploration and development and we also have potential exposure to general liability and property damage associated with the ownership of other corporate assets. In the past, we relied primarily on the operators of our oil and gas properties to obtain and maintain liability insurance for our working interest in our oil and gas properties. In some cases, we may continue to rely on those operators' insurance coverage policies depending on the coverage. Since 2011 we have obtained our own insurance policies for our oil and gas operations that are broader in scope and coverage and are in our control. We also maintain insurance policies for liabilities associated with and damage to general corporate assets.

We also have separate policies for environmental exposures related to our prior ownership of the water treatment plant operations related to our discontinued mining operations. These policies provide coverage for remediation events adversely impacting the environment. See “Insurance” below.

We would be liable for claims in excess of coverage and for any deductible provided for in the relevant policy. If uncovered liabilities are substantial, payment could adversely impact the Company’s cash on hand, resulting in possible curtailment of operations. Moreover, some liabilities are not insurable at a reasonable cost or at all.

***Oil and gas operations are subject to environmental and other regulations that can materially adversely affect the timing and cost of operations.***

Our operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of human health and safety, the environment and natural resources. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the handling or disposal of wastes and other substances associated with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species and/or species of special statewide concern or their habitats;
- requiring investigatory and remedial actions to address pollution caused by our operations or attributable to former operations;
- requiring noise, lighting, visual impact, odor and/or dust mitigation, setbacks, landscaping, fencing, and other measures;
- restricting access to certain equipment or areas to a limited set of employees or contractors who have proper certification or permits to conduct work (e.g., confined space entry and process safety maintenance requirements); and
- restricting or even prohibiting water use based upon availability, impacts or other factors.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial or restoration obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, local restrictions, such as state or local moratoria, city ordinances, zoning laws and traffic regulations, may restrict or prohibit the execution of operational plans. In addition, third parties, such as neighboring landowners, may file claims alleging property damage, nuisance or personal injury arising from our operations or from the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. We monitor developments at the federal, state and local levels to inform our actions pertaining to future regulatory requirements that might be imposed to mitigate the costs of compliance with any such requirements. We also monitor industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned in relation to pollution prevention and incident investigations.

Below is a discussion of the major environmental, health and safety laws and regulations that relate to our business. We believe that we are in material compliance with these laws and regulations. We do not believe that compliance with existing environmental, health and safety laws or regulations will have a material adverse effect on our financial condition, results of operations or cash flow. At this point, however, we cannot reasonably predict what applicable laws, regulations or guidance may eventually be adopted with respect to our operations or the ultimate cost to comply with such requirements.

***Hazardous Substances and Waste***

Federal and state laws, in particular the federal Resource Conservation and Recovery Act (RCRA) regulate hazardous and non-hazardous wastes. In the course of our operations, we and others generate petroleum hydrocarbon wastes, produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state waste laws. At various times in the past, most recently in December 2016, proposals have been made to amend RCRA or otherwise eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us, as well as our competitors, to incur significantly increased operating expenses.

Federal, state and local laws may also require us to remove or remediate wastes or hazardous substances that have been previously disposed or released into the environment. This can include removing or remediating wastes or hazardous substances disposed or released by us (or prior owners or operators) in accordance with then current laws, suspending or ceasing operations at contaminated areas, or performing remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered legally responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, persons who disposed or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to the site. CERCLA and analogous state laws also authorize the EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and/or seek recovery of the costs of such actions from responsible classes of persons.

The Underground Injection Control (UIC) Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. Permits for Class II UIC wells may be issued by the EPA or by a state regulatory agency if EPA has delegated its UIC Program authority. Because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal.

***Air Emissions***

We are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. Among other things, these laws and regulations regulate emissions of air pollutants from various industrial sources, including compressor stations and production equipment, and impose various control, monitoring and reporting requirements. Permits and related compliance obligations under the CAA, each state's development and promulgation of regulatory programs to comport with federal requirements, as well as changes to state implementation plans for controlling air emissions in regional non-attainment or near-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.

***Discharges into Waters***

The federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. Spill prevention, control and countermeasure regulations require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and construction activities.

The Oil Pollution Act of 1990 (OPA) establishes strict liability for owners and operators of facilities that release oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the United States.

***Health and Safety***

The Occupational Safety and Health Act (OSHA) and comparable state laws regulate the protection of the health and safety of employees. The federal Occupational Safety and Health Administration has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. OSHA also requires employee training and maintenance of records, and the OSHA hazard communication standard and EPA community right-to-know regulations under the Emergency Planning and Community Right-to-Know Act of 1986 require that we organize and/or disclose information about hazardous materials used or produced in our operations.

***Endangered Species***

The Endangered Species Act (ESA) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to operate could materially limit or delay our plans.

***Global Warming and Climate Change***

At the federal level, EPA regulations require companies to establish and report an inventory of greenhouse gas emissions. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the oil and natural gas that we sell. The EPA recently finalized new standards of performance limiting methane emissions from oil and gas sources. The potential increase in operating costs could include new or increased costs to (i) obtain permits, (ii) operate and maintain our equipment and facilities, (iii) install new emission controls on equipment and facilities, (iv) acquire allowances authorizing greenhouse gas emissions, (v) pay taxes related to greenhouse gas emissions and (vi) administer and manage a greenhouse gas emissions program. In addition to these federal actions, various state governments and/or regional agencies may consider enacting new legislation and/or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. The Paris Agreement could further drive regulation in the United States. Restrictions on emissions of methane or carbon dioxide that have been or may be imposed in various states, or at the federal level could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas. Finally, we note that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the Safe Drinking Water Act (the “SDWA”), and has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA announced plans to update its chloride water quality criteria for the protection of aquatic life under the Clean Water Act. Flowback and produced water from the hydraulic fracturing process contain total dissolved solids, including chlorides, and regulation of these fluids could be affected by the new criteria. The EPA has announced that it will develop pre-treatment standards for disposal of wastewater produced from shale gas operations through publicly owned treatment works. The regulations will be developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. On April 7, 2015, the EPA published a proposed rule requiring federal pre-treatment standards for wastewater generated during the hydraulic fracturing process in the Federal Register. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to publicly owned treatment facilities. The public comment period for the proposed rule ended on July 17, 2015. If the EPA implements further regulations of hydraulic fracturing, 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 could even be prohibited from drilling and/or completing certain wells.

The state of Texas has adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, several municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event state, local, or municipal legal 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 could even be prohibited from drilling and/or completing certain wells.

Several federal governmental agencies are actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. On June 4, 2015, the EPA issued a draft assessment of potential impacts to drinking water resources from hydraulic fracturing. The draft report did not find widespread impacts to drinking water from hydraulic fracturing. The EPA's inspector general released a report on July 16, 2015 recommending increased EPA oversight of permit issuances as well as the chemicals used in hydraulic fracturing. The United States Department of Energy is also actively involved in research on hydraulic fracturing practices, including groundwater protection.

On March 26, 2015, the Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands, including private surface lands with underlying federal minerals. The rule was scheduled to become effective on June 24, 2015, but was temporarily stayed by a federal court. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in hydraulic fracturing operations meet certain construction standards, development of appropriate plans for managing flowback water that returns to the surface, heightened standards for interim storage of recovered waste fluids, and submission of detailed information to the BLM regarding the geology, depth and location of pre-existing wells. Several states, tribes, and industry groups filed several pending lawsuits challenging the rule and the BLM's authority to regulate hydraulic fracturing. In February 2016 the U.S. District Court in Wyoming issued a preliminary injunction staying implantation of BLM's hydraulic fracturing regulations. BLM has appealed the preliminary injunction to the Tenth Circuit Court of Appeals. The outcome of this litigation is uncertain. If the rule becomes effective, we expect to incur additional costs to comply with such requirements that may be significant in nature, and we could experience delays or even curtailment in the pursuit of hydraulic fracturing activities in certain wells. The rule could also affect drilling units that include both private and federal mineral resources.

Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. If hydraulic fracturing becomes regulated at the federal level, our fracturing activities could become subject to additional permit or disclosure requirements, associated permitting delays, operational restrictions, litigation risk, and potential cost increases. Additionally, certain members of Congress have called upon the United States Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the United States Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The United States Geological Survey Offices of Energy Resources Program, Water Resources and Natural Hazards and Environmental Health Offices also have ongoing research projects on hydraulic fracturing. These ongoing studies, depending on their course and outcomes, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory processes.

Further, on August 16, 2012, the EPA issued final rules subjecting all new and modified oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards ("NSPS") and all existing and new operations to the National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards require the use of reduced emission completion ("REC") techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line beginning in January 2015. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAP include maximum achievable control technology ("MACT") standards for those glycol dehydrators and certain storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. These rules will require additional control equipment, changes to procedure, and extensive monitoring and reporting. The EPA stated in January 2013, however, that it intends to reconsider portions of the final rule. On September 23, 2013, the EPA published new standards for storage tanks subject to the NSPS. In December 2014, the EPA finalized additional updates to the 2012 NSPS. The amendments clarified stages for flowback and the point at which green completion equipment is required and updated requirements for storage tanks and leak detection requirements for processing plants. The EPA has stated that it continues to review other issues raised in petitions for reconsideration.

On December 17, 2014, the EPA proposed to revise and lower the existing 75 ppb National Ambient Air Quality Standard ("NAAQS") for ozone under the federal Clean Air Act to a range within 65-70 ppb. On October 1, 2015, EPA finalized a rule that lowered the standard to 70 ppb. This lowered ozone NAAQS could result in an expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and gas operations in ozone nonattainment areas likely would be subject to more stringent emission controls, emission offset requirements for new sources, and increased permitting delays and costs. This could require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

The EPA also has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the TSCA rulemaking.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. Over the past few years, several court cases have addressed aspects of hydraulic fracturing. In a case that could delay operations on public lands, a court in California held that the BLM did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. Courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or regulation could also lead to operational delays or restrictions or increased costs in the exploration for, and production of, oil, natural gas, and associated liquids, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state, or local laws, or the implementation of new regulations, regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.

***Requirements to reduce gas flaring could have an adverse effect on our operations.***

Wells in the Bakken and Three Forks formations in North Dakota, where we have significant operations, produce natural gas as well as crude oil. Constraints in the current gas gathering and processing network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the North Dakota Industrial Commission, North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. The Commission is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals.

In addition, oil and gas projects are subject to extensive permitting requirements. Failure to timely obtain required permits to start operations at a project could cause delay and/or the failure of the project resulting in a potential write-off of the investments made.

***Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.***

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of crude oil, natural gas, and NGLs requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of crude oil, natural gas, and NGLs.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

***Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas, and NGLs***

In December 2009, the EPA made a finding that emissions of carbon dioxide, methane, and other “greenhouse gases” endanger public health and the environment because emissions of such gases contribute to warming of the earth’s atmosphere and other climatic changes. Based on this finding, the EPA has adopted and implemented a comprehensive suite of regulations to restrict and otherwise regulate emissions of greenhouse gases under existing provisions of the CAA. In particular, the EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA. One rule requires a reduction in greenhouse gas emissions from motor vehicles, and the other regulates permitting and greenhouse gas emissions from certain large stationary sources. These EPA regulatory actions have been challenged by various industry groups, initially in the D.C. Circuit, which in 2012 ruled in favor of the EPA in all respects. However, in June 2014, the United States Supreme Court reversed the D.C. Circuit and struck down the EPA’s greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. As a result of that ruling, large sources of air pollutants other than greenhouse gases would still be required to implement the best available capture technology for greenhouse gases.

The EPA has also adopted reporting rules for greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries as well as certain onshore oil and gas extraction and production facilities.

Several other kinds of cases on greenhouse gases have been heard by the courts in recent years. While courts have generally declined to assign direct liability for climate change to large sources of greenhouse gas emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant greenhouse gas emissions, and new claims for damages and increased government scrutiny will likely continue. Such cases often seek to challenge air emissions permits that greenhouse gas emitters apply for, seek to force emitters to reduce their emissions, or seek damages for alleged climate change impacts to the environment, people, and property. Any court rulings, laws or regulations that restrict or require reduced emissions of greenhouse gases could lead to increased operating and compliance costs, and could have an adverse effect on demand for the oil and gas that we produce.

***Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.***

Oil and gas operations in the Williston Basin and the Gulf Coast can be adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and gas activities sometimes cannot be conducted as effectively during the winter months, and this can materially increase our operating and capital costs. Gulf Coast operations are also subject to the risk of adverse weather events, including hurricanes.

***Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.***

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with oil and gas prices and activity levels in new regions, caus